Oil and Gas Technical Work Group
Option Proposals - Summaries with Appendices

	Summary List of Option Proposals	Lead(s)
O&G 1	Best Conservation Practices	Jim Pfeiffer
O&G 2	Reductions in Fugitive Methane Emissions	Jane Williamson
O&G 3	Electrification of Oil and Gas Operations, with Centralized Power Production and Distribution	Sean Lowther
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O&G 1 Best Conservation Practices

Executive Summary

The Best Conservation Practices Policy Option reduces direct carbon dioxide emissions through common-sense measures that minimize fuel consumption. Specific initiatives will be developed to suit the needs of specific conservation opportunities. Such initiatives/opportunities include (but are not limited to):

- Consumption of liquid fuel at/in support of North Slope Oil Fields; (described more below)
- Minimize fuel required for operation of flares;
- Optimize existing process to minimize energy consumption;
- Reduce miles driven in support of operations by employees and contractors;

- Increase fuel economy of vehicles used in support of operations;
- Cut electricity use in offices and camps.

Option Design

The option reduces carbon emissions by managing down the amount of fuel used to support production of Oil & Gas operations in Alaska. The option is largely behavior-based and is achieved by ongoing encouragement to individuals in making good conservation choices and, through repetition, for those choices to become habits. The option does not require large capital projects to accomplish.

Goals

- Enroll oil & gas workforce in energy conservation efforts;
- Reduce fuel/energy used in support of oil & gas operations.

Timing and Parties Involved

- North Slope Producers;
- ADEC public outreach function;
- GreenStar Program?;
- Option is intended to be implemented near term (0-2 years).

Option Implementation Mechanisms

The option would be implemented through a workforce outreach program to share best practices for reducing fuel consumption. Initial sharing from SOA/ADEC regarding successful implementation of public outreach programs such as the “Plug It In at 20 Degrees” program. Sharing best practices and individual/organizational recognition programs could be developed through the GreenStar program, the SOA website, and/or North Slope producer intranet sites.

Relationship to Other Efforts

- North Slope Producers have begun efforts;
- GreenStar program already established to coordinate similar efforts;
- ADEC and the Municipality of Anchorage have successfully performed similar outreach.

Key Uncertainties

There are other opportunities, not yet identified within our efforts. Our efforts need to be focused upon accomplishing these reductions in an efficient manner. A mechanism to ensure easy, cooperative, public transfer of applicable knowledge, expertise, and technical training to the Alaska oil and gas stakeholders needs to be developed. Expert oil and gas assistance will be needed to help develop a process to attain that goal. This assistance may come from within industry, government, and the University system.

The State and Federal governments and oil and gas industry should work cooperatively and ensure funding to develop programs and policies that result in greenhouse gas reduction through energy conservation. Alaska has an abundance of oil and gas technical expertise; Alaska citizens with many years of training. Their talents and technical input are required to ensure efficient, successful progress in this effort. The State of Alaska and industry should help ensure Alaskan expertise is retained and that adequate training is provided to future generations.

Feasibility Issues

There are no significant feasibility issues with implementation of this option. Conservation efforts will need to be tempered by operational integrity and life safety issues, particularly on the North Slope.

Benefits

This option will result in near-term reductions of carbon emissions, as well as emissions of conventional pollutants. There are more opportunities that the O&G TWG have not yet identified that could significantly decrease greenhouse gases and increase oil and gas reserves. With appropriate policies towards training and retaining technically qualified individuals within the industry, State government, and University programs, future generations will have greater opportunities within the State.

Costs

It is believed no additional SOA budget is necessary to implement. Policy option will require modest amount of ADEC focus related to sharing best practices and coordination of effort. Costs to O&G producers in Alaska will be modest and will vary by initiative.

Other Impacts

The option will enroll the Alaskan oil & gas workforce in conservation efforts, allowing those behaviors to be leveraged to find further reduction opportunities.

Initiative Description- Reduce Liquid Fuel Consumption on the North Slope

The focus of this initiative is reducing consumption of liquid fuel at/in support of North Slope Oil Fields.

Initiative Design

The initiative reduces carbon emissions by reducing the amount of liquid fuel consumed through trip reduction, idling management, fleet transformation, smarter use of support equipment (Tioga heaters, light plants, etc), and any other measures to reduce liquid fuel consumption.

Goals

- Enroll oil & gas workforce in liquid fuel conservation efforts;
- Minimize liquid fuel used to support North Slope oil & gas operations.

Timing and Parties Involved

- North Slope Producers and contractors;
- Option is intended to be implemented now.

Initiative Implementation Mechanisms

Initiative would use same implementation mechanisms as described in the conservation option.

Relationship to Other Efforts

- Would be coordinated with other conservation initiatives.

Key Uncertainties

The extent of reductions available through this initiative.

Feasibility Issues

There are no significant feasibility issues with implementation of this option. Conservation efforts will need to be tempered by life safety issues.

Benefits

This option will result in near-term reductions of carbon emissions, as well as emissions of conventional pollutants.

Costs

It is believed no additional SOA budget is necessary to implement. Policy option will require modest amount of ADEC focus related to sharing best practices and coordination of effort. North Slope producers have efforts underway to reduce liquid fuel consumption due to expense and logistics issues related to importation of ULSD, and the option would not increase costs.

Other Impacts

The option increases net production of petroleum in Alaska. The option reduces the risk of fuel spills from intrastate transportation. The option helps reduce market pressure on Alaska-produced Ultra-Low Sulfur Diesel (ULSD).

O&G 2: Reductions in Fugitive Methane Emissions

Executive Summary

This option relates to reductions in fugitive methane emissions. In this option, the following would be explored:

a) Refinements to fugitive methane inventories;

b) Assessment of potential reductions of fugitive methane;

c) Development of model fugitive methane reduction programs appropriate to Alaska Oil & Gas Operations.

Very rough order of magnitude fugitive methane emissions are estimated by ICF International at +/- 0.162 million metric tonnes CO_2e per year[1], with nearly all occurring in the upstream oil and gas production and processing operations. As the volumes estimated are low, we believe a major study specific of economics and opportunities to reduce fugitive methane or to develop a model fugitive methane reduction program is not appropriate at this time due to the small volume involved. However, we endorse inclusion of this option within a category of smaller scale energy conservation and GHG reductions. This effort would explore Alaska relevant opportunities that can be implemented within the next five years and also identify funding and policy opportunities to help us get through the next phase.

Policy Implications/Recommendations

Operators are required to obtain approval and to report purposeful venting to the Alaska Oil and Gas Conservation Commission (AOGCC) as well as any flaring within the oil and gas fields. For 2007, the reported volume for methane venting was 45 million standard cubic feet or about .015 million metric

[1] Appendix E, Table E-2 of the Alaska GHG Inventory estimated roughly 3 million metric tonnes CO_2e for the oil and gas operations in 2005. While ICF did not have access to the full model used in the inventory, they believe the tool may have used emission factors not intended for "fugitive" methane and are much higher than that of IPPC guidelines. The ICF summary is provided as an Appendix to this document.

tonnes CO_2e per year. The Commission will continue to ensure that operators consistently report such emissions, and work with ADEC to ensure reporting requirements can easily be imported into any final GHG inventory database.
Encouragement of efforts to reduce fugitive methane emissions on a case by case basis is appropriate. Work is proceeding on the federal level (EPA/DOE) and within API to develop estimation methods for fugitive methane. We recommend the State of Alaska follow that work, but not "re-invent the wheel" as these volumes appear to be low. If fugitive emission reporting is required under any federal legislation, we can follow the requirements laid out within those regulations at that time.
While the costs to reduce fugitive methane may be low on a case by case basis, development of model fugitive methane reduction programs could be very time consuming, and potentially take focus away from more important issues and from actual accomplishment of the emission reduction.

Potential Benefit to State

While a more comprehensive estimation method and audit would be required to better estimate fugitive methane emission volumes in a "bottoms-up", field by field approach, ICF rough order of magnitude estimated volumes are about .16 million metric tonnes CO_2e. If full elimination of the fugitive methane is accomplished, roughly 450 million standard cubic feet per year could be recovered for sale or in field use as fuel. The potential reduction would be on a case by case basis.

Qualitative Summary of the Potential Cost and GHG Savings

While dependent upon the particular situation, we would anticipate costs of some reduction efforts may be low, and could be accomplished relatively quickly. However, some fixes could be more complex and costly, and potentially require some production shut-in to achieve.
For fugitive methane reduction, we are concerned that significant costs could result if high accuracy is expected for measurement of volumes. Care should be taken that options to measure/report/ decrease methane fugitive emission are not overkill and delay progress in actual reduction in greenhouse gases. Further work by the O&G TWG, with help of technical expertise within their own organizations is needed to help identify and quantify costs and GHG savings from energy conservation options.

Implementation Path

Determine actual Alaska fugitive emissions sizes and locations. Make recommendation on appropriate types of monitoring/estimating methods appropriate to identify and prioritize fugitive methane sources. After identification of sizes and sources, encourage appropriate mitigations.
Until the inventory is better understood, the State should emphasize the need for extra diligence at all oil and gas operations, especially as part of an overall emphasis on conservation and anti-waste practices. This may fit well with one of the Cross Cutting TWG options of encouraging overall conservation practices.

Research Needs

If a high amount of accuracy is needed to measure fugitive methane, new tools, R&D for finding leaks and measuring volumes may be required.

O&G 2: Appendix A

Reductions in fugitive methane emissions

Summary of Proposed Option

This option relates to evaluation of the feasibility and economics of reductions in fugitive methane emissions. In this option, the following would be explored:

a) Refinements to fugitive methane inventories;

b) Assessment of potential reductions of fugitive methane;

c) Development of model fugitive methane reduction programs appropriate to Alaska Oil & Gas Operations.

The Oil and Gas Technical Working Group (TWG) with the assistance of ICF International has reviewed the potential impact of fugitive methane emissions within the oil and gas sector. Fugitive methane emissions are unintentional releases of methane to the atmosphere such as leaks from valves, flanges, unions, tube fittings, or buried pipe. Very rough order of magnitude fugitive methane emissions is estimated at +/- 0.162 million metric tonnes CO_2e per year[21]. Nearly all fugitive methane emissions occur within the upstream oil and gas production and processing operations.

The Alaska Oil and Gas Conservation Commission requires approval and reporting of any purposeful venting of methane gas, as well as any flaring within the oil and gas fields. For 2007, the reported volumes for methane venting were 45 million standard cubic feet or about .015 metric tonnes CO_2e per year. The Commission will continue to ensure that operators consistently report such emissions, and work with ADEC to ensure reporting requirements can easily be imported into any final GHG inventory database.

It is the TWG's opinion that a major study specific to fugitive methane is not appropriate at this time, and specific Alaska policy options as regards fugitive methane are premature. Work is proceeding on the federal level (EPA/DOE) and within API to develop estimation methods for fugitive methane. However, if the MAG wishes to proceed, an option is set forth below.

Option Details

Purposed: The purpose of the work would be to identify appropriate tools to identify fugitive methane emission sources and volume levels of fugitive methane emissions in Alaska's oil and gas fields, through existing methodology developed for the oil and gas sector, and to decrease fugitive methane emissions to enable capture for sale or use in oil and gas operations.

The following is the path we suggest:

1. The appointed group/agency investigate options for fugitive methane emission estimates and as appropriate, obtain guidance from DOE EPA as to expected final protocol.

2. Using the emission estimate protocol developed, or specified by the appropriate regulatory agency, a comprehensive, field specific estimate could be required.

3. Operators could then investigate major potential contributors to methane emissions per estimates, and attempt to check validity.

[1] Appendix E, Table E-2 of the Alaska GHG Inventory estimated roughly 3 million metric tonnes CO2e for the oil and gas operations in 2005. While ICF did not have access to the full model used in the inventory, they believe the tool may have used emission factors not intended for "fugitive" methane and are much higher than that of IPCC guidelines. The ICF summary is provided in the Appendix to this document.

4. Changes in operations or equipment to reduce fugitive methane emissions should be on a case by case basis dependent upon cost/benefit analysis.

Overview

Fugitive Methane Definition:

Methane emissions in the oil and natural gas industry are classified into three categories:

- vented
- fugitive
- combusted

Vented methane emissions are designed, intentional releases such as when depressurizing a vessel or pipe for maintenance or emergency situations. Operators are required to request approval and report such emissions within monthly gas disposition reports. Vented volumes reported to the Commission in 2007 was 41.5 million scf, or approximately .015 million metric tonnes CO_2e. These volumes were mainly related to gas escaping when wells are occasionally produced to tanks or portable separator equipment (such as exploratory activity, blowdown of gas wells loaded with water to resume production, etc.)

Fugitive methane emissions are unintentional releases of methane to the atmosphere such as leaks from valves, flanges, unions, tube fittings, or buried pipe.

Combusted emissions are the exhaust gases from combustion occurring in equipment such as stationary engines, stationary boilers, and mobile sources which are primarily carbon dioxide but also contain a small percentage of nitrous oxide and methane—all three of which are greenhouse gases.

In general, fugitive methane emissions occur primarily upstream of refining in the oil and gas infrastructure, such as at wells and at production facilities. Oil wells, associated gas and oil wells, gas wells, and reinjection wells all have fittings, valves, flanges, and other components where connections have been made and a potential leak to the atmosphere may occur. Production facilities with separators, pumps, compressors, tanks, headers, test vessels, meters to separate oil/water/gas have similar components, and each component is a potential leak source for methane.

Emissions at the oil refinery and further downstream tend to be small relative to the upstream emissions. Oil entering the refinery has been depressurized to atmospheric pressure and also possibly stabilized to have a lower vapor pressure, meaning that virtually all of the methane has been degassed from the oil. Though fugitives may still occur in refineries and further downstream in the oil industry, these fugitives will be of other hydrocarbons and not methane. Refinery fuel gas systems containing natural gas may result in some methane fugitives, but the product streams themselves will not result in a material volume of fugitive methane emissions.

Timing:

If it is found that funding for major consultancy is required, a full scope of work will be prepared on the basis of the 2009 work, and request for funding for the FY 2011 budget cycle will be submitted in late 2009.

Geographic Focus:

This review will be for all oil and gas facilities prior to sales at Lease Automated Custody Transfer Meters (LACT). Downstream transportation and refinery review is not expected within this study.

Evaluation Focus Areas:

- **Who needs to be involved with study (if required)**
  - ADEC

- All Oil and Gas Operators
- AOGCC

- **Relevant legislation and regulations**

  Existing
  - Statutes and regulations are in place related to prevention of waste of hydrocarbons, gas disposition reporting, and flare/venting approvals.

  Under development or needed
  - Depending upon results in 2009, and following in step with federal or state policy requirements, further regulation may be required.
  - Streamlining of reporting requirements of ADEC, AOGCC, and other regulatory agencies using the information will be needed.
  - Incorporation of EPA regulations, if any, and other federal laws regarding air quality, carbon tax or cap and trade, etc

- **Incentives : Financial, Permitting, etc**
  - Monitoring of volumes, and improvements which could act as potential credits to apply to potential future tax or cap and trade allocations.
  - Streamline permitting and reporting (coordinate with ADEC).

Key uncertainties to be captured in the studies

Further review of the appropriate fugitive methane volume estimation tool.
Accuracy expectations for purposes of cap and trade or carbon tax.

Feasibility Considerations

If high amount of accuracy expected, new tools, R&D for finding leaks and measuring volumes would be required.
It should be recognized that once carbon becomes a traded commodity, accounting of the gases may actually hinder efforts in GHG reduction. Care should be taken that options to measure/report/ decrease methane fugitive emission are not overkill and actually delay implementation.

O&G 2 Appendix B - DISCUSSION OF FUGITIVE METHANE EMISSIONS FROM OIL & GAS PRODUCTION IN ALASKA
Prepared by Brian Gillis and Fran Sussman, ICF International

This document is in support of the Alaska Climate Change Strategy and the Oil and Gas (O&G) Technical Work Group (TWG). It addresses some of the questions that have arisen about the quantity of fugitive methane emissions from Alaska's oil and gas production, and the possibility of including mitigation options for these emissions in the recommendations of the O&G TWG.
The document has four parts

A) Clarification of the terminology defining fugitive methane emissions
B) Discussion and comparison of the major references providing estimates for fugitive methane emissions
C) Presentation of some alternative emissions factors from the literature
D) A rough, order of magnitude estimate of fugitive methane emissions for Alaska
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A) Fugitive Methane Emissions Defined

Methane emissions in the oil and natural gas industry are classified into three categories:

- vented
- fugitive
- combusted

Vented methane emissions are designed, intentional releases such as when depressurizing a vessel or pipe for maintenance or emergency situations. **Fugitive** methane emissions are unintentional releases of methane to the atmosphere such as leaks from valves, flanges, unions, tube fittings, or buried pipe. **Combusted** emissions are the exhaust gases from combustion occurring in equipment such as stationary engines, stationary boilers, and mobile sources which are primarily carbon dioxide but also contain a small percentage of nitrous oxide and methane—all three of which are greenhouse gases.

While both oil and natural gas production result in fugitive methane emissions, the bulk of fugitive emissions in Alaska are likely to arise from oil production because of Alaska's comparative focus on oil production. The same is likely to be true for Alaska's contribution to U.S. emissions, as well. The Energy Information Administration (EIA) reports that, in 2007, Alaska produced an average of 741 thousand barrels oil per day, or about 15 percent of U.S. production.[3] EIA also reports that Alaska's dry natural gas production in 2006 was 420.086 billion cubic feet, or about 2 percent of U.S. production.[4]

In general, fugitive methane emissions occur primarily upstream of refining in the oil and gas infrastructure, such as at wells and at production facilities. Oil wells, associated gas and oil wells, gas wells, and reinjection wells all have fittings, valves, flanges, and other components where connections have been made and a potential leak to the atmosphere may occur. Production facilities with separators, pumps, compressors, tanks, headers, test vessels, meters to separate oil/water/gas have similar components, and each component is a potential leak source for methane.

On average for a component, upstream fugitive emissions of methane will be much smaller for petroleum than natural gas, since petroleum components are in liquid service and natural gas components are in gas service. In the petroleum industry, components in oil, condensate, or water service may have leaks which will result in hydrocarbon emissions to the atmosphere. Because methane is dissolved in upstream oil, condensate, and water along with these other hydrocarbons, only a small portion of these emissions will be methane. In contrast, components in natural gas service such as gas wells, gas/liquids separators, or reinjection wells may have leaks with a greater overall methane content given that methane is the primary component of natural gas.

Emissions at the oil refinery and further downstream tend to be small relative to the upstream emissions. Oil entering the refinery has been depressurized to atmospheric pressure and also possibly stabilized to have a lower vapor pressure, meaning that virtually all of the methane has been degassed from the oil. Though fugitives may still occur in refineries and further downstream in the oil industry, these fugitives will be of other hydrocarbons and not methane. Refinery fuel gas systems containing

[3] www.eia.doe.gov/emeu/mer/pdf/pages/sec3_3.pdf
[4] tonto.eia.doe.gov/dnav/ng/ng_sum_snd_dcu_nus_a.htm. No EIA data on gas for 2007 is available yet. [?? Do you mean "2007?"]

natural gas may result in some methane fugitives, but the product streams themselves will not result in a material volume of fugitive methane emissions.[5]

B) Major References for Fugitive Methane Emissions

The three methane emissions categories—fugitive, vented, and combusted--are the commonly accepted categories used by the authoritative studies on oil and natural gas sector greenhouse gas emissions from both the public and private sectors. Below is a brief discussion of public sector U.S. studies, private sector U.S. studies, and international studies.

Public sector U.S. studies

The 1996 EPA/GRI *Methane Emissions from the Natural Gas Industry*[6] is a study published by EPA to characterize this sector's methane emissions at a national level. The 1996 EPA/GRI study follows the three methane emissions categories shown above, describing fugitives in page 19 of Volume 2 as "unintentional leaks emitted from sealed surfaces, such as packing and gaskets, or leaks from underground pipelines (resulting from corrosion, faulty connections, etc.)." EPA's annual *Inventory of U.S. Greenhouse Gas Emissions and Sinks*[7] estimates national methane emissions from all sectors, and for the petroleum systems sector and the natural gas systems sector, it follows the definitions and methods of the 1996 EPA/GRI study, using almost all of the original 1996 emission factors.

Private sector U.S. studies

In the private sector, the American Petroleum Institute's (API) *Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry*[8] is a guidance document for individual companies to inventory greenhouse gas emissions. The API Compendium lists its emission source classification in Table 1-1, page 1-5 which lists the fugitive sources as "valves, flanges, connectors, pumps, compressor seal leaks," and also other non-point sources of "wastewater treatment and surface impoundments." The Compendium includes many methods for fugitive methane emissions quantification, one of which is to apply the 1996 EPA/GRI emission factors. Work by other industry associations such as the Interstate Natural Gas Association of America (INGAA) and International Petroleum Industry Environmental Conservation Association (IPIECA) draw from methods also published in the Compendium. Several greenhouse gas inventory tools or software are available to collect and calculate emissions at a company level and offer various degrees of automation. SANGEA[9] is one such tool which has emission factors again taken from the 1996 EPA/GRI study.

International studies

At the international level, the Intergovernmental Panel on Climate Change (IPCC) published guidance documents intended to assist countries complete greenhouse gas emissions inventories. The *Revised 1996 IPCC Guidelines for National Greenhouse Gas Inventories*[10] provide methods and default emission factors for estimating emissions at a granular level appropriate for national reporting but not entity reporting such as by companies. The revised IPCC guidelines describe in the glossary[11] fugitive emissions as "intentional or unintentional releases of gases from anthropogenic activities." The IPCC definition is therefore different from the definitions used by the reference documents specific to U.S. inventories.

C) Comparison of Selected emissions factors for Oil Production

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[5] Methane emissions associated with Alaska's natural gas processing, transmission, and distribution is likely to be very small and so is not estimated here.

[6] Each of the 15 volumes available from www.epa.gov/gasstar/tools/related.html

[7] www.epa.gov/climatechange/emissions/usinventoryreport.html

[8] www.api.org/ehs/climate/new/upload/2004_COMPENDIUM.pdf

[9] ghg.api.org/

[10] www.ipcc-nggip.iges.or.jp/public/gl/guidelin/ch1ref8.pdf

[11] www.ipcc-nggip.iges.or.jp/public/gl/guidelin/glosri.pdf

ICF also investigated Alaska's SGIT emissions inventory tool being discussed by TWG members and compared these factors to what is known from the major references discussed above in B). The SGIT tool estimates methane emissions from oil production using a single emissions factor which we believe is representing not only fugitive emissions but also vented and combusted emissions.

Below is a table showing the emission factor from the SGIT Tool and other fugitive methane emission factors from greenhouse gas inventory reference documents. Note that U.S. EPA emission factors from the Emissions Inventory Improvement Program (EIIP) are not shown, as this program is revising its factors to be consistent with the U.S. EPA National Greenhouse Gas Inventory factors, which are in the table.

		Emission Factors			
Source Category	**Units**	**SGIT Tool**	**Revised 1996 IPCC Guidelines**	**API Compendium, facility level onshore**	**U.S. EPA National GHG Inventory**
Petroleum Production	kilograms methane / thousand barrels	366.21	29.28	234.23	no explicit basis of comparison, different methodology. But implicit emissions factor (based on 2006 inventory) is 21.7.

Sources:
www.ipcc-nggip.iges.or.jp/public/gl/guidelin/ch1ref8.pdf Table 1-58
www.api.org/ehs/climate/new/upload/2004_COMPENDIUM.pdf page 6-5
http://yosemite.epa.gov/OAR/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2006.html

The SGIT Tool oil production factor is the highest of all those shown in the table, and ICF suspects that this factor is not intended to represent fugitive emissions or only fugitive emissions. No comparison is possible between the SGIT tool factor and those used in the U.S. EPA National inventory since the national inventory uses more specific source categories each with their own emissions factors (number of wells, number of separators, number of heaters, etc) rather than the higher-tier approach in the SGIT Tool of using a single overall production volume with one factor.

The factors in the table above vary significantly given that some are intended for top-down, country level use (Revised 1996 IPCC Guidelines) while others are intended for bottom-up, facility level use (API Compendium). The U.S. EPA national GHG inventory factor shown is an implicit factor derived from many bottom-up emission factors. ICF suspects that the SGIT tool factor is also implicitly derived from many separate emission factors and that the factors may not represent only fugitive methane emissions.

D) Fugitive Methane Emissions: Order-of-Magnitude Estimate for Alaska

Given the accepted definition of fugitive emissions used by major U.S. studies and the available data provided by those studies, we can derive an order-of-magnitude estimate for Alaska fugitive methane emissions. Inventories are typically either bottom-up approaches which identify and quantify each source of methane emissions or top-down approaches which apportion emissions based on an estimate for a larger boundary. Since we seek an order-of-magnitude estimate, a top-down approach is appropriate.

EPA's *Inventory of U.S. Greenhouse Gas Emissions and Sinks* provides annual estimates of total U.S. greenhouse gas emissions and also subtotals by industry sector. The inventory is released for public comment each year, undertakes a continuous improvements program, and is a good basis for estimating fugitive methane emissions from Alaska oil and gas production in a top-down manner. The relevant industry sectors in the inventory for this TWG are petroleum systems and natural gas systems. The boundaries for petroleum systems in the inventory are all U.S. oil production, transportation, and refining. The boundaries for natural gas systems are all U.S. gas production, gathering, processing, transmission, and distribution. For wells producing both associated gas and oil, the interface between these two inventory sectors is at the oil/gas separator immediately after a well: gas off the top of the separator is considered the natural gas systems sector, and oil off the bottom of the separator is considered to be part of the petroleum systems sector.

The aggregate U.S. estimates for fugitive methane emissions for oil and natural gas production can be scaled down by the magnitude of production in Alaska relative to the U.S. This suggests that total fugitive methane emissions from oil and gas production in Alaska is on the order of **0.162 Teragrams (million metric tons) CO_2e.**

The derivation of this figure is provided in appendix C, and consists of:

- Petroleum systems: 0.135 Teragrams CO_2e
- Natural gas production: 0.027 Teragrams CO_2e

While much smaller than some estimates the TWG has been working from, fugitive methane emissions may still represent a source of “low hanging fruit” in the oil and gas industry in Alaska. This short memo does not discuss whether or not mitigation is a cost-effective option for Alaska. Much depends on

- whether the scaling approach is appropriate as a method of estimating emissions in Alaska
- the cost of reducing fugitive emissions, given technologies in use
- the market value of recovered methane

O&G 2 APPENDIX C: DERIVATION OF ESTIMATED FUGITIVE METHANE EMISSIONS FOR ALASKA

Within the petroleum systems sector of the EPA inventory are sector subtotals which aggregate sources of interest. Table 3-39[12] shows the petroleum systems subtotals through the 2006 reporting year in Teragrams (million metric tons) CO_2e and is reproduced below.

Table 3-39: CH_4 Emissions from Petroleum Systems (Tg CO_2 Eq.)

Activity	1990	1995	2000	2001	2002	2003	2004	2005	2006
Production Field Operations	**33.2**	**31.3**	**29.6**	**29.5**	**29.2**	**28.5**	**28.0**	**27.6**	**27.7**
Pneumatic device venting	10.3	9.7	9.0	8.9	8.9	8.7	8.6	8.3	8.4
Tank venting	3.8	3.4	3.2	3.2	3.2	3.1	3.0	2.8	2.9
Combustion & process upsets	1.9	1.7	1.6	1.6	1.6	1.5	1.5	1.5	1.5
Misc. venting & fugitives	16.8	16.0	15.3	15.3	15.1	14.7	14.5	14.5	14.5
Wellhead fugitives	0.5	0.5	0.5	0.5	0.5	0.5	0.4	0.4	0.4
Crude Oil Transportation	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**
Refining	**0.5**	**0.5**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**	**0.6**
Total	**33.9**	**32.0**	**30.3**	**30.2**	**29.9**	**29.2**	**28.7**	**28.3**	**28.4**

Note: Totals may not sum due to independent rounding.

Source: www.epa.gov/climatechange/emissions/downloads/08_Energy.pdf

Note that these subtotals were created in the source document to illustrate specific ideas such as wellhead versus non-wellhead emissions, and as a result total fugitives are not neatly shown in one subtotal and have to be derived. The wellhead fugitives subtotal shows 0.4 Teragrams CO2e in 2006. The subtotal "Misc venting & fugitives" also contains some fugitive emissions sources, but this subtotal's emissions are mostly from large vent sources. The amount of fugitives in the "Misc venting & fugitives" subtotal can be derived upon examining Annex 3[13] of the inventory and is approximately 0.5 Teragrams CO_2e. Therefore, total petroleum system fugitives are 0.4 + 0.5 = 0.9 Teragrams CO_2e. Since Alaska produces approximately 15 percent of U.S. crude oil, scaling fugitives by this percentage results in **0.135 Teragrams CO_2e methane fugitives from Alaska petroleum systems.**

The natural gas systems sector of the EPA inventory also has subtotals allowing us to examine fugitives. Table3-34[12] shows the subtotal categories through 2006 in Teragrams (million metric tons) CO_2e and is reproduced below.

[12] www.epa.gov/climatechange/emissions/downloads/08_Energy.pdf
[13] www.epa.gov/climatechange/emissions/downloads/08_Annex_3.pdf

Table 3-34: CH_4 Emissions from Natural Gas Systems (Tg CO_2 Eq.)[a]

Stage	1990	1995	2000	2001	2002	2003	2004	2005	2006
Field Production	32.7	37.2	38.8	41.5	42.5	40.1	32.9	25.0	27.6
Processing	14.9	14.9	14.6	14.7	14.2	13.6	13.4	11.8	11.9
Transmission and Storage	46.3	45.8	43.8	40.7	42.4	42.8	40.9	38.5	38.2
Distribution	30.8	30.1	29.3	28.5	25.8	26.9	26.8	27.2	24.7
Total	**124.7**	**128.1**	**126.5**	**125.3**	**124.9**	**123.3**	**114.0**	**102.5**	**102.4**

[a] Including CH_4 emission reductions achieved by the Natural Gas STAR program and NESHAP regulations.
Note: Totals may not sum due to independent rounding.

Source: www.epa.gov/climatechange/emissions/downloads/08_Energy.pdf

These categories were not intended to display the contribution from fugitive emissions, though it can be discerned from Annex 3[13] of the inventory that approximately 5 percent of the field production emissions are from fugitives. Thus, the national fugitives estimate for gas production is approximately 5 percent of 27.6 Teragrams CO_2e, or 1.38 Teragrams CO_2e. Apportioning this by Alaska's 2 percent production share of U.S. natural gas gives **0.027 Teragrams CO_2e methane fugitives from Alaska natural gas production.**

Summing the Alaska petroleum systems estimate and the Alaska natural gas production estimate gives **0.162 Teragrams CO_2e methane fugitives from Alaska oil and gas.**

O&G 3: Electrification of Oil and Gas Operations, with Centralized Power Production and Distribution

Executive Summary

This option recommends the State of Alaska and the Oil and Gas stake holders study the economics and technical feasibility of developing a centralized power sharing and distribution system to serve Alaska's major oil and gas operations, and possibly expected expansion areas.
To maximize benefits and efficiencies, this option should be implemented in conjunction with O&G 4 and 5 to provide a comprehensive thermal efficiency upgrade package for hydrocarbon recovery activities. (See Appendix A for additional details)

Policy Implications/recommendations

The State of Alaska should encourage Oil and Gas stake holders to invest in centralized electrical power generation on the North Slope through a facilitated coordinated regulatory environment, as well as incentivizing the massive capital investments that will be required.
The State of Alaska should ensure that it has on staff a trained and experienced workforce to implement the large permitting and regulatory changes for the North Slope Operations within its agencies to help for the facilitate the implementation of the GHG reduction options.

Potential Benefit to State

This has a direct financial benefit for the state as well as a greenhouse gas emissions benefit.
The state would benefit from a centralized power grid at major oil and gas operations (especially the North Slope), in that the major efficiencies gained mean less fuel burned, and more fuel ultimately

available for sale. In addition, the citizens of the state would benefit as the less fuel burned, the smaller the amount of GHG emissions.

Qualitative Summary of the Potential Cost and GHG Savings

There is a very large potential cost of this option, with a very rough estimated in the 100's of Millions of dollars to Billions of dollars depending on the scope and complexity. Maximum benefits would be gained through implementing this option in conjunction with Option 2, improving the efficiency of oil and gas equipment. These options together have the potential to cut GHG output from North Slope hydrocarbon recovery activities by greater than two-thirds of the current GHG emissions.
In the Oil and Gas production, transport, and refining sector on the North Slope there are 11 Million Metric Tons of CO_2e produced each year[14]. Assuming that we can improve the overall thermal efficiency of oil and gas operations by two and two thirds of the current efficiency, this would translate into a GHG reduction of greater than 7 Million Metric Tons of CO_2e.
If this option is done in concert with Options 4, 5, 7, and 8 the overall GHG savings could end up being greater than 70%, of the baseline values.[15]

Implementation Path

To minimize time required for implementation, regulatory and capital investment hurdles should be addressed immediately by both the State and the stake holders. The critical path is for State to design incentives to facilitate a significant level of capital investments, operators to begin design of facilities needed to maximize the GHG reductions within an acceptable economic framework. Large factors in the economics of this option are values for carbon and for natural gas.

Research Needs

The technical and economic feasibility and any and all incentives should be fully investigated and a recommendation for each and every project individually and reviewed as a collective of projects to ensure both short term and long term vision is maintained.
Economic Research Areas-

- Determine what the period of performance is for the projects and the study
- Model and recommend the most effective incentives to encourage the capital investment in thermal efficiency improvements for hydrocarbon recovery activities. The study should take into account any effects on the economy and jobs within the sector and its supporting businesses.
- Research the value of carbon near and long term to determine the value of avoided emissions.
- Research the value of natural gas over the required performance period for the study

Technical Research Areas-

- Engage with Federal, State or Private Entities that may be doing research efficiency upgrades.
- Producing power on the North Slope where both the Methane and potential geological sequestration space are abundant, performing CO_2 capture and sequestration as EOR and

[14] Based on data compiled by the state for 2002
[15] See footnote 1

transporting the power via very long power lines to markets in and outside of Alaska. Research focus should be on the ability to transport power over long distances.

O&G 3 Appendix A: Additional Supporting Documentation

Details on the Option

Proposal: To have the MAG propose that the Sub-Cabinet recommend that the State of Alaska and the Oil and Gas Stake Holders work together to perform a study with the use of a knowledgeable independent party to evaluate the economic and technical feasibility of centralizing power and electrification of oil and gas operations within the state. The goal of the study would be to evaluate the technical, economic and regulatory feasibility of maximizing the GHG reductions within oil and gas operations through economies of scale realized by creating centralized electrical power with energy efficient equipment. Options may include repowering using combined cycle plants and/or high efficiency simple cycle turbines, waste heat reuse, process optimization, right sizing of equipment or other technology improvements. This electricity in turn will power electric variable speed pumps, compressors and other hardware that is currently gas or diesel fired. This has great potential to produce a significant improvement in the thermal efficiency for North Slope Operations and less so for Cook Inlet Operations, thus reducing the total fuel burned. This will both conserve the natural gas resource and reduce GHG release. The study must also include any and all changes that maybe/are required to regulations, statues, lease agreements, tax or royalty obligations to ensure the effective implementation of the option

Timing: Expected timing for the study:

– The State should initiate the required legislative, regulatory, technical and economic studies **immediately**, as some of the items should have very long lead times for review and then implementation (i.e. regulatory and legislative changes)

– Prior to the gas line being built, the implementation of the plan could have significant impact on long term hydrocarbon recovery (improved reserves due to less of the gas burned as fuel, providing pressure support for oil recovery and more salable gas for a major gas sale). The scenario appears to have significant technical merit, but could fail due to current lease restrictions and complex regulatory hurdles.

– A Major North Slope gas sale may bring economic feasibility to the project by giving a value to the North Slope gas. Additionally the implementation of a cost of carbon through federal GHG regulations and State incentives may make projects economically competitive as compared to current operations, depending on value/cost associated with carbon.

– The largest GHG reductions are dependent on the completion of a gas pipeline. This is because a vast amount of the GHG emissions from North Slope operations come from re-injecting field gas back into the the reservoirs for pressure support resulting in greater oil recovery. The process has older technology turbines that may or may not be very energy efficient. A detailed engineering analysis should be performed looking at current technologies and any available process improvements.

- Possible GHG Cap and Trade or Carbon Tax Legislation would provide a cost of carbon emissions, thus giving economic impetus for facilities investments needed to improve efficiencies and reduce GHG emissions.
- 2010 Pipeline Open Season will give a cost of gas. When the gas line is completed North Slope gas will have an associated value, and thus be a saleable commodity.
- Facilities installation and grid electrification should occur before the start of a Major Gas Sales (+/- 2020)
- A Major Gas Sales should help bring currently uneconomic oil and gas projects on line and increase the life of the field, thereby providing more economic incentives for facilities upgrade and centralized electric grid.
- There is a possibility that complex and multiple year regulatory changes are required. The study should look at these to help the stakeholders understand what the regulatory time frame is for implementation of their GHG reduction projects. This will allow the companies to understand how to scope the projects, and assist in making the implementation more efficient.

Geographic Focus: On both the North Slope and in the Cook Inlet, where feasible technically and economically on a project by project basis. North Slope and Cook Inlet must be evaluated separately, as the economic considerations are different between the two geographic areas. The most power is utilized on the North Slope, with the largest amount generated at the Prudhoe Bay field. The biggest potential savings in GHG emissions are there.

Evaluation Focus Areas

- **Who needs to be involved with study**
  - Companies, Regulatory Agencies (EPA, ADEC, MMS, ADNR, ADOR, COE, AOGCC, NSB, RCA, etc…)
- **Relevant Legislation and Regulations**
  - Legislative and Regulatory changes (both federal and state) are needed for existing air quality regulations so that greenhouse gas reduction projects can be implemented simply and efficiently without regulatory conflicts. Issues surround existing New Source Review requirements and greenhouse gas reduction projects.
  - The State GHG Washington DC Contact should work directly with Climate Change staff in Washington DC and Congress to shape federal legislation and regulations. Dialogue and input from stakeholders in Alaska needs to be routine and is an essential part of the process.
  - Streamlining and coordination between federal and state regulations
  - Avoid duplicating or potentially conflicting regulations with existing or expected federal regulations
  - Thorough analysis of utility statute and regulations for unintended consequences that restrict GHG reduction projects. Concerns surround becoming subject to utility requirements.
  - Changes to tax credit legislation and regulations to provide incentives for greenhouse gas reduction improvement projects may be required to facilitate project economics

- Trained qualified regulatory staffing, and retention (ADEC, ADNR, RCA, AOGCC other) will improve timing and efficiency
- Streamlining of permitting of new/revised facilities that are going to reduce GHG's
- Royalties and lease term impacts of centralized power grid

- **Financial, Permitting, or other incentives**
  - Permitting incentives: streamlining, accelerated permitting or authorizations, land use,
  - Financial incentives: emission credits, tax credits, bonds, technology investment, favorable lease terms, royalty reduction, emission credits

<u>Related Programs and Policies:</u>

- Energy Efficiency: Option 2: Part of the creation of the power plant would be through the implementation of technologies that would require the lowest amount of hydrocarbon consumption per unit output.
- CO_2 Capture and sequestration Options 6, 7 and 8 including:
  - capture from exhaust from the fuel burning equipment
  - pre-combustion capture – conversion to hydrogen for fuel, CO_2 captured
  - Fuel and sales gas treatment, capture, and sequestration of naturally entrained CO_2 gas before combustion
- North Slope Major Gas Sales (Brings value to the gas for the North Slope and economics for facilities upgrades and electrification)
- Renewable Energy (improved thermal efficiency from non hydrocarbon consuming sources)

<u>Estimated GHG Savings and Costs Per MMT CO_2e</u>

- Required analysis to be accomplished

  Develop Scope

  Project Specific and based on incentives

  Meet with ES&D TWG
- Data sources, methods, and assumptions
- Key uncertainties

<u>Feasibility Considerations</u>

- Direct Feasibility Issues
  - State Agencies
    - Trained and Qualified Staff with a sufficient budget (Fiscal Note (assuring staffing through sufficient agency funding for multiple years, to ensure full and complete implementation of necessary GHG projects)
    - Cross Agency Working Groups (DNR, MMS, Etc…)
    - Regulatory Reform / Federal, AOGCC, DNR, Local (NSB) etc…
  - Commercial Terms

  - North Slope (Unit by Unit) lease terms may create disincentive for (gas) fuel use efficiency
  - Other fiscal terms
  - IPP regulation (BP, Conoco, Pioneer etc… When do you become a utility)
  - (Agency Issues) RCA/DEC/MMS/Federal Agencies/ Land Use Permitting
  - Operating Agreements
- Costs (Based on value of Gas and Value of CO_2) Prioritize projects and separately evaluate high ranking options
- Time Frame
  - North slope - Until Major Gas Sales occurs, making high fuel usage costly, or carbon legislation is passed that places a cost on carbon emissions, a localized grid in this region may not compete economically with lower cost operating and development options, but will be technically feasible
  - Cook Inlet – The economic and technical feasibility should be viewed separately from the North Slope operations. Cook Inlet is nearing end of usable production life for the known fields, and additional exploration and hydrocarbon recovery projects may change the economic and technical feasibility for this region, and or for the individual project.
- Logistics of transporting equipment, Haul road maintenance and possible upgrade
- Procurement of equipment to implement the GHG projects

Additional Information

- There may be additional benefits and costs that are not directly Greenhouse Gas related that we should highlight. These would include, but are not limited to an overall Fuel Savings (lower waste), Lower NO_X, Lower SO_2, And Lower PM?
  - Improved energy efficiency in gas constrained fields will result in short term lower oil production rate; however long term hydrocarbon recovery will be improved
  - Water Issues (Water Demand and Disposal related to steam production)
  - Demand for Durable Goods (Turbines, infrastructure, capital improvements)
  - Additional short term jobs to implement projects
  - Qualified personnel to operate and maintain the updated equipment
  - Waste (Abandonment of scrap)
  - Land use cost increases
  - Benefits to nearby communities and to expanding oil and gas exploration through access to the electric grid

O&G 4: Improved Efficiency Upgrades for Oil and Gas Fuel Burning Equipment

Executive Summary

This option recommends the State of Alaska and the Oil and Gas stake holders study the economics and technical feasibility of replacing older technology equipment with newer high efficiency equipment to improve overall thermal efficiency, thus reducing GHG emissions per unit of generated power.
To maximize benefits and efficiencies, this option should be implemented in conjunction with O&G 3 and 5 to provide a comprehensive thermal efficiency upgrade package for hydrocarbon recovery activities. (See Appendix A for additional details.)

Policy Implications/recommendations

The State of Alaska should encourage the Oil and Gas stake holders to invest in capital projects to improve the overall efficiency of oil and gas fuel burning equipment.
The State of Alaska should ensure that it has on staff a trained and experienced workforce to implement the large permitting and regulatory changes for the North Slope Operations within its agencies to help for the facilitate the implementation of the GHG reduction options.

Potential Benefit to State

This has a direct financial benefit for the state as well as a greenhouse gas emissions benefit.
The state would benefit from upgrades in efficiencies of fuel burning equipment in that there will be greater overall saleable hydrocarbons recovered from the oil and gas production areas, as fewer hydrocarbons will need to be used for fueling operations. In addition, the citizens of the state would benefit as the less fuels burned, the smaller the amounts of GHG emissions.

Qualitative Summary of the Potential Cost and GHG Savings

There is a very large potential cost of this option, with a very rough estimated in the 100's of Millions to Billions of dollars. This option has the potential to cut GHG output from North Slope hydrocarbon recovery activities by possibly 5.5 Million Metric tons.
In the Oil and Gas production, transport, and refining sector on the North Slope there are 11 Million Metric Tons of CO_2e produced each year[16]. Assuming that we can improve the overall thermal efficiency of oil and gas operations equipment by double what it is today, this would translate into a GHG reduction of greater than 5.5 Million Metric Tons of CO_2e.
If this option is done in concert with Options 3, 5, 7 and 8 the overall GHG savings could end up being greater than 70%, of the baseline values.[17]

Implementation Path

To minimize time required for implementation, regulatory and capital investment hurdles should be addressed immediately by both the State and the stake holders. The critical path is for State to design incentives to facilitate a significant level of capital investments in more efficient fuel burning equipment compared to the current equipment employed in hydrocarbon recovery activities. The various operators should begin review of all of the in service fuel burning equipment and how they could be

[16] Based on data compiled by the state for 2002
[17] See footnote 1

replaced with newer higher thermal efficiency equipment. A review of the design of the facilities is needed to ensure that we are maximizing the GHG reductions within an acceptable economic framework. Large factors in the economics of this option are values for carbon and for natural gas.

Research Needs

The technical and economic feasibility and any and all incentives should be fully investigated and a recommendation for each and every project individually and reviewed as a collective of projects to ensure both short term and long term vision is maintained.

Economic Research Areas-

- Determine what the period of performance is for the projects and the study
- Model and recommend the most effective incentives to encourage the capital investment in thermal efficiency improvements for hydrocarbon recovery activities. The study should take into account any effects on the economy and jobs within the sector and its supporting businesses.
- Research the value of carbon near and long term to determine the value of avoided emissions.
- Research the value of natural gas over the required performance period for the study

Technical Research Areas-

- Engage with Federal, State or Private entities that may be doing research in energy efficiency improvements in equipment
- Study alternative low CO_2 producing fuels that have upfront CO_2 capture, such as Hydrogen produced from field gas Methane.
- Review changes in current technologies for simple changes that could improve thermal efficiency such as firing temperature changes or thermal efficiency improvement packages from the manufacturers[18]

O&G 4 Apppendix A: Additional Supporting Documentation

Details on the Option

Proposal: The State of Alaska and the Oil and Gas Stake Holders work together to perform a study through individual producers, refiners, and pipeline companies to perform a self audit on energy efficiency within their operations, and work with a knowledgeable third party to evaluate the economic and technical feasibility of the improving the efficiency of equipment for oil and gas operations within the state. Care must be taken to maintain confidentiality, as this information could compromise competitive advantage if it is shared across companies. The Independent party would compile the audit results and assure consistency and confidentiality. The goal of the study would be to evaluate the technical and economic feasibility of maximizing GHG reductions within the oil and gas sector (Upstream/Mid/Down) through highly energy efficient equipment replacing aging lower efficiency machinery. Options to be studied include cross unit equipment sharing, repowering using combined cycle plants and/or high efficiency simple cycle turbines, waste heat reuse, process optimization, right sizing of equipment or other technology improvements. Reducing

[18] Could have a negative impact in NOx production forcing NSR review

the total fuel burned will both conserve the natural gas resource and reduce GHG release. The study should also include any and all changes that may be or are required to regulations, statues, lease agreements, tax or royalty obligations to ensure the effective implementation of any recommendations.

Timing: Expected timing for the study:

- The State should initiate the required legislative, regulatory, technical and economic studies **immediately**, as some of the items may have very long lead times for review and implementation (i.e. regulatory and legislative changes).

- The implementation of the plan could increase long term hydrocarbon recovery. While technical feasibility is likely for the North Slope Operations, many upgrades may be uneconomic without appropriate incentives.

- A Major North Slope gas sale may bring economic feasibility to the project by giving a value to the North Slope gas. Additionally the implementation of a cost of carbon through federal GHG regulations and State incentives may make projects economically competitive as compared to current operations, depending on value/cost associated with carbon. For example, a tax credit for the costs associated with installation of cleaner burning equipment and the removal of older technology.

- The largest GHG reductions are dependent on completion of gas pipeline construction. This is because a vast amount of the GHG emissions from North Slope operations comes from the process of re-injecting field gas back into the reservoirs for pressure support resulting in greater oil recovery. There will be reinjection of CO2 and reinjection of a portion of the Field Gas, so the evaluation will need to take this into account. The existing turbines are older technology that may or may not be very energy efficient. This requires a detailed engineering analysis looking at current technologies and/or any possible process improvements.
- Possible GHG Cap and Trade or Carbon Tax Legislation will provide a cost of carbon emissions, thus giving economic impetus for facility investments to reduce GHG emissions. This will be reviewed on a company by company basis, for each of their facilities and will be a market driven at this point.
- 2010 Pipeline Open Season will give a value to gas. When the gas line is completed, North Slope will have an associated value, and thus be a saleable commodity. Energy efficiency projects could be economically viable with a realized dollar savings associated with fuel savings.
- Facilities installation should occur before the start of a Major Gas Sales (+/- 2020)
- A Major Gas Sales should help bring currently uneconomic oil and gas projects on line and increase the life of the field, thereby providing more economic incentives for facilities upgrade and centralized electric grid.
- Smaller scale GHG reductions are possible in 3 to 5 years dependent on regulatory changes, economics and agency staffing
- Multiple year regulatory changes are required, to understand what the regulatory time frame is for implementation. This will allow the companies to understand how to scope the projects.

Geographic Focus: Facilities on the North Slope have the highest potential savings, followed by facilities in the Cook Inlet area, but efficiencies can be gained anywhere if technically feasible and should be addressed on a project by project basis. Projects will be prioritized, and then more promising options will be evaluated separately, as the economics depend on multiple factors, including location, type and age of the machinery to be analyzed, etc.

Evaluation Focus Areas

- Type of Study (Independent producer self audit potentially complied by 3rd party for consistency)
- Energy Audit Process to drive best management practices
- **Study Participants (Inclusive not exclusive)**
  - Companies, Regulatory Agencies (ADEC) and/or (ADNR – PSIO?) to oversee study
    - Other Agencies to be kept in the loop (AOGCC, MMS, others as required)
- **Relevant Legislation and Regulations**
  - Legislative and Regulatory changes (both federal and state) are needed to existing air quality regulations so that greenhouse gas reduction projects can be implemented simply and efficiently without regulatory conflicts. Identify any possible barriers to ease of implementation due to possible conflicts between New Source Review requirements and greenhouse gas reduction projects.
  - The State's GHG Washington DC Contact should work directly with Climate Change staff in Washington DC and Congress to shape federal legislation and regulations. Dialogue and input from stakeholders in Alaska needs to be routine and an essential part of the process. This should be done to ensure expeditious implementation, to maximize the benefits for everyone.
  - Streamlining and coordination between federal and state regulations
  - Changes to tax credit legislation and regulations for greenhouse gas reduction projects may be required to facilitate project economics.
  - Trained qualified regulatory staffing, and retention at (ADEC, AOGCC, ADNR, etc) will improve timing and efficiency
  - Streamlining of permitting for new/revised facilities planned to reduce GHG's
  - Royalties and lease term impacts
- **Financial, Permitting, or other incentives**
  - Review and develop appropriate and necessary incentive programs to facilitate project economics.

- Permitting incentives: streamlining, accelerated permitting or authorizations, land use,
- Financial incentives: emission credits, tax credits, bonds, technology investment, lease terms, royalties, emission credits

Related Programs and Policies:

- Electrification of Oil and Gas: Option 1: Part of the creation of the power plant would be through the implementation of technologies that would require the lowest amount of hydrocarbon consumption per unit output.
- Option 8, CO_2 Capture and sequestration (exhaust from the fuel burning equipment)
- Fuel and sales gas treatment, and sequestration of naturally entrained CO_2 gas before combustion, Option 6
- North Slope Major Gas Sales (Brings value to the gas for the North Slope and economics for facilities upgrades)
- Renewable Energy (improved overall energy efficiency from non hydrocarbon consuming sources)

Estimated GHG Savings and Costs Per MMTCO$_2$e

- Required analysis to be accomplished
  - Develop Scope and priority
  - Project Specific and based on incentives
- Data sources, methods, and assumptions
- Key uncertainties

Feasibility Considerations

- Direct Feasibility Issues
  - State Agencies
    - Trained and Qualified Staff with a sufficient budget (Fiscal Note, multiple years)
    - Cross Agency Working Groups (DNR, MMS, Etc…)
  - Commercial Terms
    - North Slope (Unit by Unit) lease terms may create disincentive for (gas) fuel use efficiency
    - Royalty Payments across unit boundaries
    - Any possible impact of IPP regulation

- (Agency Issues) RCA/DEC/MMS/Federal Agencies/ Land Use Permitting
- Regulatory Reform / Federal, AOGCC, DNR, Local (NSB) etc…
- Operating Agreements

– Screening Level Cost and Benefit analysis (Based on value of Gas and Value of CO_2) Identify any Low cost high benefit projects, help prioritize

– Time Frame

- North Slope - If a carbon Cap and Trade of Tax is put in place, this project may become economically competitive compared to current operations. However, we believe this option to be technically feasible. Furthermore, reduction of fuel gas would allow for more salable gas during a major North Slope gas sale.
- Cook Inlet – Feasibility should be viewed separately from the North Slope operations. Cook Inlet is nearing end of usable production life for the known fields, and additional exploration and hydrocarbon recovery projects may change the economic and technical feasibility for projects in this region.
- Refineries and Pipelines – Studies/self audit can begin soon, but as in upstream operations, economics will be affected by the price of carbon.

– Logistics of transporting equipment, Haul road maintenance and possible upgrade

– Procurement of equipment to implement the GHG projects

Additional Information

- Are there any additional Benefits and Costs that are not directly Greenhouse Gas related that we should highlight. These would include, but are not limited to an overall Fuel Savings (lower waste), Lower NO_X, Lower SO_2, And Lower PM?

  – Improved energy efficiency in gas constrained fields will result in short term lower oil production rate; however long term hydrocarbon recovery will be improved
  – Water Issues (Water Demand and Disposal related to steam production)
  – Demand for Durable Goods (Turbines, infrastructure, capital improvements)
  – Additional short term jobs to implement projects
  – Qualified personnel to operate and maintain the updated equipment
  – Waste (Abandonment of scrap)
  – Land use cost increases
  – Public relations – doing the right thing for the environment

O&G 5: Renewable Energy Sources in Oil and Gas Operations

Executive Summary

This recommends the State of Alaska and the Oil and Gas stake holders study the economics and technical feasibility of developing renewable energy sources to improve overall thermal efficiency, thus reducing GHG emissions per unit of generated power.

To maximize benefits and efficiencies, this option should be implemented in conjunction with O&G 3 and 4 to provide a comprehensive thermal efficiency upgrade package for hydrocarbon recovery activities. (See Appendix A for additional details.)

Policy Implications/recommendations

The State of Alaska should encourage the Oil and Gas stake holders to invest in capital projects to install renewable energy wherever possible in oil and gas operations. These are only possible where an renewable energy source is located near the Oil and Gas operation.

The State of Alaska should ensure that it has on staff a trained and experienced workforce to implement and changes in permitting and regulatory environment needed to add additional power facilities.

Potential Benefit to State

This has a direct financial benefit for the state as well as a greenhouse gas emissions benefit.

The state would benefit from adding renewable energy options to oil and gas operations as fewer hydrocarbons would have to be burned as fuel, which leaves greater overall hydrocarbons volumes available for sale. In addition, the citizens of the state would benefit as the less fuels burned, the smaller the amounts of GHG emissions.

Qualitative Summary of the Potential Cost and GHG Savings

There is a large potential cost of this option, which depends on the type and size of potential renewable energy source that could be co-located with any particular oil and gas operation. The potential savings in terms of GHG emissions would depend on the amount and type of power replaced.

The potential amount of GHG emissions saved by replacing natural gas generation and industrial heating with renewable energy source is 0-50% of the current output, depending on the availability of a renewable energy resource. This estimate is based on the idea that a vast majority of fuel burning equipment could either be replaced with alternative power sources and the portions that are not replaced require lower overall fuel demands, due to the renewable energy supplementing the fuel burning equipment. Actual savings are unknown until full evaluation of O&G operations is conducted.

Implementation Path

To minimize time required for implementation, regulatory and capital investment hurdles should be addressed immediately by both the State and the stake holders. The critical path is for State to design incentives to facilitate a research and design of arctic based renewable energy sources. This will require a significant level of capital investments, and the operators should begin to research designs and re-design of facilities needed to maximize the GHG reductions within an acceptable economic framework. This options feasibility has some bearing on both the North Slope Fuel Gas being assigned a value as well as a value for carbon.

Research Needs

The technical and economic feasibility and any and all incentives should be fully investigated and a recommendation for each and every project individually and reviewed as a collective of projects to ensure both short term and long term vision is maintained.

Economic Research Areas-

- Determine what the period of performance is for the projects and the study
- Model and recommend the most effective incentives to encourage the capital investment in renewable energy projects at oil and gas operations. The study should take into account any effects on the economy and jobs within the sector and its supporting businesses.
- Research the value of carbon near and long term to determine the value of avoided emissions.
- Research the value of natural gas over the required performance period for the study

Technical Research Areas-

- Engage with Federal, State or Private Entities that may be doing research in renewable energy sources such as wind, hydro and geothermal, especially as they related to conditions found in Alaska.
- Study location and types of renewable options to enhance the thermal efficiency of hydrocarbon recovery activities.

O&G 5 Appendix A: Additional Supporting Documentation

Details on the Option

Proposal: The State of Alaska and the Oil and Gas Share Holders conduct a study with the use of a knowledgeable independent party to evaluate the economic and technical feasibility of the addition of renewable energy sources for the oil and gas operations within the state. The goal of the study would be to provide a recommendation after a thorough evaluation of the technical and economic feasibility of reducing GHG emissions within the oil and gas sector (Upstream/Mid/Down) by augmenting traditional energy sources with renewable ones. The options may include, but are not limited to harnessing wind, geothermal and tidal energy. This will have the effect of improving the overall thermal efficiency for any oil and gas operations, by reducing the total amount of fuel burned, as well as conserving the natural gas, coal, or diesel currently used to power the facilities. The study must also include a comprehensive analysis of changes that may be required to regulations, statues, lease agreements, tax or royalty obligations to ensure the effective implementation of any recommendations resulting from the study.

Timing: Expected timing for the study:

- The State should initiate the required legislative, regulatory, technical and economic studies **immediately**, as some of the items should have very long lead times for review and then implementation (i.e. regulatory and legislative changes).

- The implementation of the plan could increase long term hydrocarbon recovery. Due to current lease agreements for the North Slope Operations, projects are more likely to be technically than economically feasible.

- A Major North Slope gas sale may bring economic feasibility to the project by giving a value to the North Slope gas. Additionally the implementation of a cost of carbon through federal GHG regulations and State incentives may make projects economically competitive as compared to current operations, depending on value/cost associated with carbon.

- The largest GHG reductions are dependent on completion of gas pipeline construction. This is because a vast amount of the GHG emissions from North Slope operations comes from the process of re-injecting field gas back into the reservoirs to provide pressure support for oil recovery. The process has older technology turbines that may or may not be very energy efficient. This requires a detailed engineering analysis looking at current technologies and process improvements.
- GHG Legislation will provide a cost of carbon emissions, thus giving economic impetus for the processing of facility changes to reduce GHG emissions. This will be reviewed on a company by company basis, for each of their facilities and will be a market driven at this point.
- 2010 Pipeline Open Season will give a cost of gas. When the gas line is completed North Slope gas will have a value associated with it, and thus be a saleable commodity. Energy efficiency projects that would not meet the economic viability test without a realized dollar savings associated with fuel savings may come into viability.
- Federal Cap and Trade
- Gas Sales
- Other GHG reductions are possible in 3 to 5 years dependent on regulatory changes, economics and agency staffing
- If there are lengthy multiple year regulatory changes required, the study will need to understand what these changes are and what the regulatory time frame is for implementation. This will allow the companies to understand how to scope the projects, with a clear understanding of the regulatory framework under which the project will be constrained.

Geographic Focus: Anywhere there is renewable energy potential, GHG reductions can be obtained. Success here depends on access to a renewable energy source, which could happen anywhere. The North Slope, followed by the Cook Inlet currently uses the most energy, but renewable energy success will depend more on access to wind, geothermal, hydro, or tidal than other considerations.

Evaluation Focus Areas

- **Who needs to be involved with study**

  - Companies, Regulatory Agencies (EPA, ADEC, MMS, ADNR, ADOR, COE, AOGCC, NSB, and RCA (if energy sharing) etc…)

- **Relevant Legislation and Regulations**
  - Legislative and Regulatory changes (both federal and state) are needed to existing air quality regulations so that greenhouse gas reduction projects can be implemented simply and efficiently without regulatory conflicts.
  - The State (Michael Tubman or equivalent) should work directly with Climate Change staff in Washington DC and Congress to shape federal legislation and regulations to ensure that they are good for Alaska and for the environment. Dialogue and input from stakeholders in Alaska needs to be routine and an essential part of the process.
  - Streamlining and coordination between federal and state regulations
  - Thorough analysis of utility statute and regulations for unintended consequences that restrict GHG reduction projects. Concerns surround becoming subject to utility requirements.
  - Changes to tax credit legislation and regulations for greenhouse gas reduction improvement projects could facilitate project economics
  - Trained qualified staffing, and retention at ADEC and other agencies will impact timing
  - Streamlining of permitting of new/revised facilities that are planned to reduce GHG's
  - Royalties and lease term impacts
- **Financial, Permitting, or other incentives**
  - Permitting incentives: emission credits, streamlining, accelerated permitting or authorizations, land use,
  - Financial incentives: tax credits, bonds, technology investment, lease terms, royalties, emission credits

<u>Related Programs and Policies:</u>

- Electrification Option 1: Part of the creation of the power plant would be through the implementation of technologies that would reduce the overall amount of hydrocarbon consumption per unit output of hydrocarbons from the usable fields, thus having more saleable product.
- Energy Efficiency: Option 2: Part of the creation of the power plant would be through the implementation of technologies that would require the lowest amount of hydrocarbon consumption per unit output.
- CO_2 Capture and sequestration Options 6 and 7 including:
  - capture from exhaust from the fuel burning equipment

- pre-combustion capture – conversion to hydrogen for fuel, CO_2 captured
- Fuel and sales gas treatment, capture, and sequestration of naturally entrained CO_2 gas before combustion

- North Slope Gas Sales (Brings value to the gas for the North Slope and economics for facilities upgrades and electrification)
- State studies (AEA, DNR) of renewable resources by geographic region.

Estimated GHG Savings and Costs Per MMTCO$_2$e

- Required analysis to be accomplished
  - Develop scope
  - Project specific and based on incentives
  - Meet with ES&D TWG
- Data sources, methods, and assumptions
- Key uncertainties

Feasibility Considerations

- Direct Feasibility Issues
  - State Agencies
    - Trained and Qualified Staff with a sufficient budget (Fiscal Note, multiple years)
    - Cross Agency Working Groups (DNR, MMS, Etc…)
    - Regulatory Reform / Federal, AOGCC, DNR, Local (NSB) etc…
  - Commercial Terms
    - North Slope (Unit by Unit) lease terms may create disincentive for (gas) fuel use efficiency
    - Other fiscal terms
    - IPP regulation (BP, Conoco, Pioneer etc… When do you become a utility, if this option includes power sharing between multiple stake holders)
    - (Agency Issues) RCA/DEC/MMS/Federal Agencies/ Land Use Permitting
    - Operating Agreements
  - Costs (Based on value of Gas and Value of CO_2) Prioritize projects and separately evaluate high ranking options

- Time Frame
  - North slope - Until Major Gas Sales occurs, making high fuel usage costly, or carbon, legislation is passed that places a cost on carbon emissions, many projects for GHG reduction may not be economically competitive. Technical feasibility will be affected by the availability of renewable resource in the vicinity, as well as the maturity and applicability of the technology.
- Cook Inlet –Cook Inlet is nearing end of usable production life for the known fields so will have additional economic challenges. Technical feasibility will depend on the availability and technologic maturity of renewable resources in the vicinity.
- Logistics of transporting equipment, Haul road maintenance and possible upgrade
- Procurement of equipment to implement the GHG projects

Additional Information

- Are there any additional Benefits and Costs that are not directly Greenhouse Gas related that we should highlight. These would include, but are not limited to an overall Fuel Savings (lower waste), Lower NO_X, Lower SO_2, And Lower PM?
  - Possible MMS studies required for marine mammal impacts of tidal; avian migration concerns with wind turbines, visible detractions from the local natural beauty.
  - Improved energy efficiency in gas constrained fields will result in short term lower oil production rate; however long term hydrocarbon recovery will be improved
  - Water Issues (Water Demand and Disposal related to steam production)
  - Demand for Durable Goods (Turbines, infrastructure, capital improvements)
  - Additional short term jobs to implement projects
  - Qualified personnel to operate and maintain the updated equipment
  - Waste (Abandonment of scrap)
  - Land use cost increases
  - Public relations – doing the right thing for the environment
  - Potential visual, fish or wildlife effects (such as birds in windmills, tidal energy effects)

O&G 6: Carbon Capture and Geologic Sequestration with Enhanced Oil Recovery from High CO_2 Fuel Gas at Prudhoe Bay

Executive Summary

This option relates to the technical feasibility and economics of the capture, transport and geologic sequestration of CO_2 (CCS) specifically from produced gas used for fuel in and around Prudhoe Bay. The goal is to remove and sequester the 10-12% CO_2 from the natural gas produced at Prudhoe before that gas is burned in power generators. The geologic sequestration should utilize a reservoir where economics can be improved from enhanced oil recovery (EOR.) This differs in nature from O&G 7, in that it refers to removing CO_2 from entrained gas before combustion, rather than from the combustion exhaust, and the technology of this kind of capture is more advanced, though has never been implemented on the North Slope. (See Appendix A for more details.)

Potential Benefit to State

In 2005, about 1.25 MMT (million metric tonnes) of CO_2 emissions on the North Slope were due to naturally occurring CO_2 entrained within the gas. In addition to the immediate benefit of capturing CO_2 prior to combustion, studying and potentially implementing a pilot for the capture and sequestration of CO_2 from fuel gas has long term benefit to eventual gas sales. Sale gas specifications will require removal of most of the CO_2 from much larger gas volumes than are currently handled. (At projected gas sales production rates of 2 to 4 Bscfd, 5 to 10 MMT CO2/yr will ultimately need to be captured and sequestered.)

In addition to the benefit of reduced CO_2 emissions, sequestering the CO_2 in a reservoir where it can be used to enhance the oil recovered has great potential value.

Qualitative Summary of the Potential Cost and GHG Savings

Huge (100's of millions of dollars) of capital expenditures will be required by facility owners as significant retrofitting of existing power generating facilities will be needed. In addition, significant amounts of fuel will be to be burned to power the capture, compression and injection process. Dependant on the type of capture technology chosen, additional water resources may also be required. Additional expenditures could also be required for CO_2 transport pipelines and injection wells, and will be required to fund a long term monitoring program. Potential GHG savings is 1 million metric tonnes.

Significant commitment from regulators will be needed to overcome existing hurdles in permitting/royalty/and regulatory environment

Policy Implications/recommendations

While this option could be implemented immediately, the smaller the amount of fuel to be treated, the less CO_2 that has to be removed and sequestered, and the less fuel burned to do so. Ideally, energy efficiencies options (3, 4, and 5) should be put into place asap to reduce overall fuel consumption as much as possible. (The additional energy usage for capture, transport, and storage of CO_2 also means the actual reduction in CO_2 emissions achieved by a CCS project is less than the volume captured.)

Key hurdles are investment/ capital cost and regulatory environment. Policies should focus on:

1) Encouraging investment through incentives (see details in Appendix A.)

2) Simplifying/streamlining the regulatory environment:

    a. Avoid overlapping regulations, ie State and Federal both regulating GHG emissions and underground injections. Recommend coordinating/participating with development of Federal regulations to both insure the regulations fit Alaska, to allow early implementation.

    b. Study State permitting/regulatory personnel requirements. Establish policies to pay and retain sufficient qualified employees to do the job.

Implementation Path

To minimize time required for implementation, regulatory and capital investment hurdles should be addressed immediately. Critical path is for State to design incentives appropriate for capital investments, operators to begin design of facilities needed to strip the CO_2 from the fuel stream, transport it to a reservoir, and inject it for EOR, and finally that State and operators start working the complicated regulatory/permitting issues. Final economics will depend on the value for carbon.

Financing CCS projects will be sensitive to that value, and will be dependent on future cap and trade or carbon tax legislation.
Longer term, this technology will need to be implemented for eventual Gas Sales, and at that point the economics will dramatically improve for treating fuel gas.

Research Needs
Economic research:

a) Answer question of appropriate incentives, ie carrot or stick most effective. Model effects on economy and jobs with various scenarios.

b) Research long term value of carbon – huge impact on economics of these projects

c) Research long term value of natural gas

Technical research:

a) Engage with/observe DOE Phase III pilot project testing of various capture and sequestration technologies.

b) Technical Feasibility study of the different entrained CO_2 capture technologies,

O&G 6 Appendix A: Additional Supporting Documentation

Carbon Capture and Geologic Sequestration with Enhanced Oil Recovery from High CO_2 Fuel Gas at Prudhoe Bay

Option Details
The goal is to determine the optimal technology and associated economics to remove and sequester the 10-12% CO_2 by volume from the natural gas produced at Prudhoe before that gas is burned in power generators. In 2005, about 1.25 MMT (million metric tonnes) of CO_2 emissions on the slope was due to naturally occurring CO_2 entrained within the gas. In addition, the optimal technology for the capture and sequestration of CO_2 from fuel gas has direct application to a gas pipeline. Commercial gas sales via a gas pipeline will require removal of most of the CO_2 from much larger gas volumes than are currently handled. (At projected gas sales production rates of 2 to 4 Bscfd, 5 to 10 MMT CO_2/yr will ultimately need to be captured and sequestered.)
The focus of this option is to evaluate relative benefits of various capture techniques (such as membrane versus solvent treatment). Of secondary focus is to provide information concerning CO_2 sequestration and EOR benefits within selected reservoirs. The choice of final sequestration site should be based on safety and long term storage capability. The more robust the economics, the faster this technology can be put into place. Since studies show that many oil fields in and around Prudhoe Bay would benefit from enhanced oil recovery, EOR should be considered wherever feasible in the planning of CCS projects on the North Slope.
Specific Recommendations:
Risks and uncertainties in the following categories should be addressed:

- Maturity of and applicability of various capture technologies
- Costs for capture, transport, and sequestration
- Potential for CO_2 leakage
- Potential EOR benefits

Detailed analysis should cover:

- Applicable capture technologies, Pros and Cons, recommendation for pilot
- Pros and cons of reservoirs for sequestration, recommendation for pilot
- Upgraded facilities requirements (including additional space needs)
- Additional power and water resource needs
- Costs for new facilities, power, and water requirements
- Costs for geological and geophysical studies for site selection
- Costs for drilling a well or wells that are not suitable for storage
- Costs for down hole well testing, maintenance and repairs
- Reservoir analysis and simulation studies
- Value from possible tax or carbon credits
- Value from added reserves due to EOR
- Estimates of CO_2 emissions avoided (includes additional emissions from capture, transport, and injection operations)
- Logistical issues related to construction and operations in an isolated arctic environment
- Risk assessment for long-term storage
- Impacts on Estimated Ultimate Recovery (EUR) and conservation/production of resources
- Regulatory requirements (ie EPA UIC program, other state and federal requirements)
- Long term monitoring needs

Timing:
Studies could start immediately dependent on resources and funding. Early studies will facilitate the earliest possible pilot implementation.

CCS Background:

This option encompasses multiple aspects of carbon capture, transport, and geologic sequestration.
Capture: Fuel Gas Treating involves removing the CO_2 from the natural gas before combustion. Since natural gas is typically dry and at an elevated pressure, the processes used for this can be more efficient than those used to remove CO2 post combustion. Solvent processes (using a chemical solvent or a physical solvent) are the norm in the processing industry for gas treating, but alternative processing utilizing membranes is also an accepted industry practice and may be more applicable to the North Slope. The fuel gas is contacted with a solvent or directed through a series of membranes and then is available for use as fuel. The CO_2 is removed from the solvent by regenerating the solvent (using heat or reduced pressure) or in the case of the membranes simply piped from the membranes to CO_2 compression and disposal. The treated natural gas is then ready for fuel use with a minimum of processing or handling.
Transport: Once the CO_2 is captured, it must be transported to the eventual sequestration site. CO_2 pipelines operate at pressures ranging from 1,250-2,200 psi. Natural gas pipelines can operate at pressures at or below 1,200 psi, so usually CO_2 pipelines are constructed specifically for transporting CO_2. (WRI, p.45.) Where the gas pipeline pressure is in the appropriate range, new lines may not be required. In the United States, an estimated 0.78 trillion cubic feet of CO_2 per year is transported through an estimated 3,900 miles of pipelines, mainly for use in EOR. (WRI, p42)
Geologic Sequestration: Next, the CO_2 must be injected into a geologic container that will not result in leakage of the CO_2 to the surface. All existing oil and gas fields have demonstrated the capability to trap hydrocarbons, so it is likely the seals and traps would be sufficient to trap CO_2 as well, especially CO_2 in its supercritical liquid phase. The geologic container should be sufficiently deep (typically at least 2500-3000 ft) to keep the CO_2 in its dense, supercritical liquid phase. Where seal and trap are not an issue,

leakage is still possible from breaches in seal integrity. These could occur due to excessive injection pressures or well bore integrity breakdown. Excessive pressures could also potentially open up faults that were previously non-conductive. Finally, as injected CO2 contacts reservoir water, the reservoir acidifies and the environment becomes more corrosive. Both surface and sub-surface facilities will need to be carefully managed for corrosion.
Reservoir selection is extremely important for both long term storage capacity and for economics. Fortunately, on the North Slope there are multiple fields that are likely suitable both for long term sequestration, and short term EOR benefits.
Risk assessment and a long term monitoring program will be required for all sequestration projects.
Enhanced Oil Recovery (EOR): Significant economic advantages can be obtained if the initial CO_2 sequestration is partnered with EOR. Where EOR is effective, and reports indicate that many fields on the North Slope would benefit (DOE, 2005, Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Alaska) injection of CO_2 'washes' out residual oil left after initial production, and while much of this CO_2 is cycled back to the surface with residual oil, a significant percentage remains trapped in the reservoir even while active cycling is taking place. The rest of the CO_2 comes back up mixed with residual oil, is separated at the surface, and re-injected into the reservoir. This cycling continues until EOR is no longer productive, at which point all the CO_2 in the reservoir remains sequestered. At that time, CO_2 could theoretically continue to be injected until injection pressure or some other operational limit is reached.
Geographic Focus:
Prudhoe Bay area
Prudhoe Bay gas is 10-12% CO_2 by volume, has facilities and infrastructure, and has multiple sequestration sites nearby that may be both safe and suitable for EOR. We recommend this be the first place studied and piloted for this technology.
Pt. Thomson and Endicott gas may be future candidates.
Cook Inlet Gas is less than 1% by volume, so this option would not apply there.

Evaluation Focus Areas

- **Who needs to be involved with study**

– Consultants for study on technical and economic feasibility

– Prudhoe Bay Operators and Working Interest Owners

– Operators of neighboring oil fields who might benefit from CO_2 EOR

– State of Alaska (ADNR, AOGCC, ADEC, ADOR, etc) and other regulatory agencies (EPA, FERC, RCA, etc)

Relevant legislation and regulations

Existing

– EPA regulations for underground injection for EOR

Under development or needed for long term (for short term pilot– could accurately be labeled as an EOR project for permitting purposes)

- EPA regulations regarding CO_2 Underground Sequestration.[19] The State may seek primacy for this activity upon final EPA rulemaking.

- EPA regulations, if any, and other federal laws regarding air quality, carbon tax or cap and trade, etc

- State/local government Permitting as necessary addressing issues beyond EPA UIC CO_2 sequestration rules

  - Ownership issues, surface rights vs mineral rights vs pore space rights

  - Long term liability at sequestration sites

  - Royalties and lease term impacts of CO_2 sequestration and use for EOR

  - Land use regulations and requirements

- Potential Federal cap and trade legislation and ultimate EPA air quality regulations

  - Potential conflict between increased fuel use (decreased hydrocarbon reserves) due to capture and injection, and benefits for reduction of CO_2 through sequestration

- **Incentives : Financial, Permitting, etc**

- Tax incentives exist in current federal Energy Plan (part of Bailout Bill.)

- Additional carbon credits, amount to be determined based on analysis

- Streamline permitting critical for project turnaround

Related Programs and Policies
This option is strongly related to O&G 7, "CCS in and near O+G fields with potential EOR."

There are many synergies with eventual sales of North Slope gas.

On a broader scale, the following overarching considerations are recognized as critical to maximizing implementation efficiency of any Carbon Capture and Geologic Sequestration Project.

- **Evaluate how possible GHG regulation programs (cap-and-trade, carbon tax, command and control) could impact the O&G industry in Alaska given today's economics and technology;**

- Assure Up-Front Planning for budget, staffing, etc.;

- Prepare for regional tradeoffs amongst carbon and currently regulated pollutants;

[19] New EPA Underground Protection Control Proposed rules for new Class VI Underground Protection Control have been out for comment (comments due 12/24/08). AOGCC participating through Interstate Oil and Gas Compact Commission and Ground Water Protection Council. State may apply for primacy when final rules are adopted. See www.epa.gov/ogwdw/uic/wells_sequestration.html for further information.

- Consider streamlined permitting that allows permits for projects that offer GHG emissions reductions to be expedited;

- Use this information to inform policy makers.

The TWG recommends these overarching considerations be addressed in the next phase of analysis.

Estimated GHG Savings and Costs Per MMT CO_2e

- **Required analysis to be accomplished**

1) Analysis of costs/benefits for different mechanisms of fuel gas treating for carbon dioxide removal. Options should be compared on a tons CO_2 avoided basis (tons CO_2 captured – tons CO_2 generated by capture, transport, and storage processes).
2) Identification and cost estimate of additional infrastructure that would be required for the capture, transport, and injection of CO_2.
3) Identification and cost estimate of new or upgraded well construction if required for injection of potentially corrosive (if mixed with H_2O) CO_2. Studies are needed to determine how well materials hold up to long term exposure to various concentrations of CO_2
4) EOR analysis of reservoir

- **Data sources for the analysis, methods, and assumptions**

Consultant for evaluation
Prudhoe Bay Operators
Literature search on capture and sequestration (EPA, IOGCC, DOE)

- **Key uncertainties to be captured in the studies**

Cost
Hydrocarbon reserves impact
Technology
Regulatory Environment
    What amount of leakage is authorized (any? a percentage?)
Long term CCS (How long is long term?)
Liability, how long, who?
Public acceptance NIMBY

Feasibility Considerations

- Costs

- Available technology, technology maturity

- Logistical, Legal, and Royalty issues of cross unit operations

- Long term monitoring

- Conflicting regulatory requirements
- Time Frame, how long to permit? Build?
- Logistics, space for new facilities? Availability of new required equipment?

Additional Information

Are there any additional Benefits and Costs that are not directly Greenhouse Gas related that we should highlight. These would include, but are not limited to an overall Fuel Savings (lower waste), Lower NOx, Lower SO_2, And Lower PM?

- **Benefits**
  - EOR benefit
- **Costs**
  - Parasitic energy demand 10-20% extra power requirements, possible additional water requirements. Impacts on state royalties and company income
  - Increased operating costs
  - Impact on Global competitive standing if cost structure in US significantly higher than places without emissions limits.

O&G 7: Carbon Capture and Geologic Sequestration with Enhanced Oil Recovery in and near existing Oil or Gas Fields

Executive Summary

This option relates to the technical feasibility and economics of CO_2 capture, transport and geologic sequestration in or near existing Alaska oil and gas fields, including the upside of initial enhanced oil recovery (EOR.) Initial focus is intended to be on combustion sources (flue, or exhaust gases) generated on the North Slope, specifically Prudhoe Bay field, as Prudhoe facilities are the largest of Alaska's CO_2 stationary source emissions.

A significant portion of the stationary CO_2 emissions in Alaska are from the North Slope, and are a result of combustion for power generation in the oil fields. Fortuitously, the co-located or nearby oil and gas reservoirs provide likely storage space, with many of the oil reservoirs being likely candidates for CO_2 enhanced oil recovery. (See Appendix A for additional details.)

Potential Benefit to State

The 2002 estimate of CO_2 emissions related to oil and gas production at Prudhoe Bay is 9 MMT, almost ½ of all stationary GHG emissions in Alaska. Technically, a significant portion could be captured and injected into a nearby reservoir.

In addition to the benefit of reducing CO_2 emissions, sequestering the CO_2 in a reservoir where it can be used to enhance the oil recovered has significant impact on the economics.

Qualitative Summary of the Potential Cost and GHG Savings

100's of millions to billions in capital expenditures will be required by facility owners as significant additional retrofitting of existing power generating facilities will be needed. In addition, significant amounts of extra fuel (10-40%) will be needed to power the capture, compression and injection process. Dependant on the type of capture technology chosen, additional water resources may also be required. Expenditures could also be needed for CO_2 pipelines and injection wells, and will be required to fund a long term monitoring program.

Significant commitment from regulators will be needed to overcome existing hurdles in permitting/royalty/and regulatory environment

Potential GHG savings could be quite significant, up to 90% of emissions can avoided through a CCS process.

Policy Implications/recommendations

Because of the additional use of fuel required for capture, transport, and injection of CO_2, and the resultant GHG emissions related to its combustion, this option should be implemented only after or possibly concurrently with any and all energy efficiencies that can be put into place to first reduce emissions (see Options 3,4,and 5). The less fuel burned overall, the less GHG to deal with.

Key hurdles are investment/ capital cost and regulatory environment. Policies should focus on:

3) Encouraging investment through incentives (see details in Appendix A.)

4) Simplifying/streamlining the regulatory environment:

    a. Avoid overlapping regulations, ie State and Federal both regulating GHG emissions and underground injections. Recommend coordinating/participating with development of Federal regulations to both insure the regulations fit Alaska, to allow early implementation.

    b. Study State permitting/regulatory personnel requirements. Establish policies to pay and retain sufficient qualified employees to do the job.

Implementation Path

To minimize time required for implementation, regulatory and capital investment hurdles should be addressed immediately. Critical path is for State to design incentives appropriate for capital investments, operators to begin design of facilities needed to strip the CO_2 from the individual fuel exhaust streams, transport it to appropriate reservoirs, and inject it for EOR. Studies should include space, power requirements, and water requirements for each facility. Finally, the State and operators should immediately start working the complicated regulatory/permitting issues. Final economics will depend on the value for carbon. Financing CCS projects will be sensitive to that value, and will be dependent on future cap and trade or carbon tax legislation.

Research Needs

Economic research:

d) Answer question of appropriate incentives, ie carrot or stick most effective. Model effects on economy and jobs with various scenarios.

e) Research long term value of carbon – huge impact on economics of these projects

f) Research long term value of natural gas

Technical research:
Engage with/observe DOE Phase III pilot project testing of various capture and sequestration technologies.
Technical feasibility study of the North Slope, specifically Prudhoe requirements to retrofit existing equipment to add capture technology, add pipelines, additional compressors and dehydrators, and wells needed to inject CO_2.

O&G 7 Appendix A: Additional Supporting Documentation

Carbon Capture and Geologic Sequestration in and near Existing Oil or Gas Fields

Option Details

CO_2 capture, transport, and geologic sequestration (CCS) involve multiple, new and complex technologies. It is critical to determine the applicability of all aspects of a CCS program (capture, transport, and sequestration) for CO_2 sources in and near existing Alaska oil and gas reservoirs. In addition, an understanding of the risks and expected costs related to the different technologies will be critical in choosing the best one for Alaska.
In Alaska, CO_2 capture and geologic sequestration has the highest potential value on the North Slope.

- About half of all stationary sources of GHG emissions in Alaska are located on the North Slope, 75% of those are generated in the Prudhoe Bay field.
- CCS projects on the North Slope have high potential to benefit economically from Enhanced Oil Recovery (EOR).

The extreme temperatures, logistical isolation, and environmental sensitivity provide a unique operating environment that needs to be well understood before large scale capture and sequestration can responsibly begin.

Specific Recommendations:
Risks and uncertainties in the following categories should be addressed:

- Maturity of technology
- Costs for capture, transport, and sequestration
- Potential for CO_2 leakage

Detailed analysis should cover:

- Pros and cons of capture facilities locations
- Pros and cons of reservoirs for sequestration/EOR
- Costs for geological and geophysical studies for site selection
- Costs for drilling a well or wells that are not suitable for storage
- Costs for down hole well testing, maintenance and repairs
- Reservoir analysis and simulation studies
- Upgraded facilities requirements (including additional space needs)
- Additional power and water resource needs
- Costs for new facilities, ‘parasitic’ power, and water requirements
- Value from possible tax or carbon credits, and from added reserves (if EOR can be implemented as part of the initial sequestration)
- Estimates of CO_2 emissions avoided (includes additional emissions from capture, transport, and injection operations)
- Logistical issues related to construction and operations in an isolated arctic environment
- Risk assessment for storage

- Impacts on Estimated Ultimate Recovery (EUR) and conservation/production of resources (ie impact on EOR recovery of maximizing CO_2 storage)
- Regulatory requirements (ie EPA UIC program, other state and federal requirements)
- Monitoring needs (pre-, during, and post-injection)

Timing:
Studies could start immediately dependent on resources and funding. Early studies will facilitate the earliest possible implementation.
Long term implications: Assuming that venting will not be allowed (due to current and expected new regulatory requirements), the need for mitigation options such as CCS (Carbon Capture and Geologic Storage) will dramatically increase with the advent of North Slope gas sales. 10-12% of the natural gas at Prudhoe is CO_2, and most of that will need to be separated (due to sales gas specifications) and geologically sequestered. At a projected gas sales production rate of 2-4 Bscfd, 250 to 500 MMscfd (million standard cubic feet/day, or 5 -10 million metric tonnes/year of CO_2) will need to be captured and sequestered. This scenario is discussed in more detail in O & G option 6.

CCS Background:

This option encompasses multiple aspects of carbon capture, transport, and geologic sequestration.
Capture: Technology exists (in various stages of maturity) for pre-combustion carbon removal, post-combustion CO_2 removal from exhaust gases, oxy-firing, and CO_2 removal prior to the burning of fuel gas (or prior to gas sales.) (See Appendix B for a more detailed description of these processes.) CO_2 removal from produced gas and post combustion are commercially proven, while oxy-firing and pre combustion removal processes are in earlier stages of development. Most combustion related projects are still tied to government subsidies, and while research is ongoing to improve efficiencies, current technologies can require significant resource commitments in energy and water. 'Parasitic' energy (the additional energy required for the capture and injection of CO_2 for the same power output) requirements are in the 10-50% range, dependent on the source of the CO_2 and the mechanism used for removal. 'For example, capture of 90 percent of the CO_2 from a supercritical pulverized coal (SCPC) plant using current technologies would result in increased fuel consumption of 24-40 percent compared to similar plants without CO_2 capture and compression (IPCC 2005).' World Resources Institute (WRI) Guidelines for Carbon Dioxide Capture, Transport, and Storage, pg 25, www.wri.org) Also dependent on the source of CO_2 is the appropriate technology for capture and removal. This will need to be evaluated and adapted on a site specific basis. Construction of additional facilities (resulting in an increase in GHG emissions) will be required, and space for facilities will be an important consideration.
Transport: Once the CO_2 is captured, it must be transported to the eventual sequestration site. The CO_2 must be dehydrated and compressed for transportation and injection. Current facilities will need to be evaluated to determine if existing infrastructure can safely transport the compressed CO_2, or if additional pipelines would need to be constructed. Existing CO_2 pipelines operate at pressures ranging from 1,250-2,200 psi. Natural gas pipelines can operate at pressures at or below 1,200 psi, so usually CO_2 pipelines are constructed specifically for transporting CO_2. (WRI, p.45.) Where the gas pipeline pressure is in the appropriate range, new lines may not be required. In the United States, an estimated 0.78 trillion cubic feet of CO_2 per year is transported through an estimated 3,900 miles of pipelines, mainly for use in EOR. (WRI, p42)
Geologic Sequestration: Next, the CO_2 must be injected, into a geologic container that will not result in leakage of the CO_2 to the surface. The geologic container should be sufficiently deep to keep the CO_2 in its dense, supercritical liquid, phase (typically deeper than about 2500 ft.) Leakage can be due to

insufficient seal capacity (this uncertainty is less of a risk in an established hydrocarbon trap than an untested reservoir) as well as breaches to seal integrity. Seal breaches could occur due to excessive injection pressures or well bore integrity breakdown. Excessive pressures could also potentially open up faults that were previously non-conductive. Finally, as injected CO_2 contacts reservoir waters, the reservoir acidifies, and the environment becomes more corrosive. Both surface and sub-surface facilities will need to be carefully managed for corrosion.

Reservoir selection is extremely important. There are fewer uncertainties in known oil and gas fields, as the geologic containers are typically well understood, and a seal that will trap hydrocarbons will likely also trap supercritical, dense phase CO_2. Reservoir analysis including computer simulations, risk assessment and a long term (time frame still to be defined) monitoring program will be required for all sequestration projects.

Enhanced Oil Recovery (EOR): Significant economic advantages can be obtained if the initial CO_2 sequestration is partnered with EOR. Where EOR is effective, and reports indicate that many fields on the North Slope would benefit (DOE, 2005, Basin Oriented Strategies for CO_2 Enhanced Oil Recovery: Alaska) injection of CO_2 'washes' out residual oil left after initial production, and while much of this CO_2 is cycled back to the surface with residual oil, a significant percentage remains trapped in the reservoir even when active EOR is taking place.) The rest of the CO_2 comes back up mixed with the additional oil, is separated at the surface and re-injected into the reservoir. This cycling continues until EOR is no longer productive, at which point all the CO_2 in the reservoir remains sequestered. At that time, CO_2 could theoretically continue to be injected until injection pressure or some other operational limit is reached.

EPA is currently working on regulations that will be applied to sequestration projects, but long term, post-injection monitoring will certainly be an expectation for any sequestration site.

<u>Geographic Focus:</u>

Prudhoe Bay area

Both the biggest potential Green House Gas (GHG) reductions, and the best chance for improved economics exist at the North Slope oil fields, specifically Prudhoe Bay. Over half of Alaska's stationary GHG emissions, 12-13 Million Metric Tonnes CO_2 equivalent (MMT CO_2e), come from the slope, and 75% of that is from the Prudhoe Bay facilities. In addition, Prudhoe Bay has very good prospects for EOR in nearby oil fields, so both the biggest potential GHG savings and the best likely economics exist at Prudhoe Bay and near-by oil fields.

Long Term: Cook Inlet area

The Cook Inlet area, including the oil fields, Beluga Power Plant, the LNG plant, and the Tesoro refinery, account for approximately 15% of Alaska's Total Stationary Emissions. The oil and gas fields comprise numerous isolated small point sources while the Beluga Power plant and LNG plant provide larger capture opportunities. Opportunities for CO_2 capture and geologic sequestration, including EOR, exist, but targets are much smaller than on the North Slope. Facilities, wells, and pipelines would likely need extensive upgrades or replacements, perhaps even the need for totally new platforms in the case of the multiple reservoirs that are accessed offshore. This option should eventually be analyzed, but the priority is lower than the Slope studies as potential GHG emissions savings will certainly be much lower, and cost per ton higher, than on the North Slope.

There is potential for future coal to gas / liquids production in Cook Inlet which may present additional sources of GHG emissions which will be targets for sequestration.

<u>Evaluation Focus Areas</u>

- **Who needs to be involved with study**

– Consultants for study on technical and economic feasibility

– Prudhoe Bay Operators and Working Interest Owners

– Operators of neighboring oil fields who might benefit from CO_2 EOR

– State of Alaska (ADNR, AOGCC, ADEC, ADOR, etc) and other regulatory agencies (EPA, FERC, RCA, etc)

- **Relevant legislation and regulations**

Existing

– EPA regulations for underground injection for EOR

Under development or needed

– EPA regulations regarding CO_2 Underground Sequestration.[20] The State may seek primacy for this activity upon final EPA rulemaking.

– EPA regulations, if any, and other federal laws regarding air quality, carbon tax or cap and trade, etc

– State/local government Permitting as necessary addressing issues beyond EPA UIC CO_2 sequestration rules

  - o Ownership issues, surface rights vs mineral rights vs pore space rights
  - o Long term liability at sequestration sites
  - o Royalties and lease term impacts of CO_2 sequestration and use for EOR
  - o Land use regulations and requirements

– Potential Federal cap and trade legislation and ultimate EPA air quality regulations

  - o Potential conflict between increased fuel use (decreased hydrocarbon reserves) due to capture and injection, and benefits for reduction of CO_2 through sequestration

- **Incentives : Financial, Permitting, etc**

– Tax incentives exist in current federal Energy Plan (part of Bailout Bill.)

– Additional carbon credits, amount to be determined based on analysis

– Streamline permitting critical for project turnaround

– Consider joint agency similar to the JPO to facilitate between agencies (only needed in case of cross-unit applications.) Currently the AOGCC is the main regulatory agency for permitting for

[20] New EPA Underground Protection Control Proposed rules for new Class VI Underground Protection Control have been out for comment (comments due 12/24/08). AOGCC participating through Interstate Oil and Gas Compact Commission and Ground Water Protection Council. State may apply for primacy when final rules are adopted. See www.epa.gov/ogwdw/uic/wells_sequestration.html for further information.

underground injection of CO_2 for EOR. An additional facilitating agency might be beneficial in the case of cross-unit or special requirements mandated by eventual Federal regulations for underground injection of CO_2 for sequestration.

Related Programs and Policies

This option is strongly related to and dependent on other options being proposed by the Oil and Gas Technical working group.

1) Centralizing Electrical Power for Oil and Gas Operations, O&G 3 and
2) Improving Energy Efficiency for Oil and Gas Operations, O&G 4.
3) Remove CO_2 from fuel gas prior to use, O&G 6

In the case of emissions due to combustion, it is likely to be far more efficient to first reduce emissions as much as possible, and then capture and sequester a much smaller amount.

On a broader scale, the following overarching considerations are recognized as critical to maximizing implementation efficiency of any Carbon Capture and Geologic Sequestration Project.

- **Evaluate how possible GHG regulation programs (cap-and-trade, carbon tax, command and control) could impact the O&G industry in Alaska given today's economics and technology;**
- Assure Up-Front Planning for budget, staffing, etc.;
- Prepare for regional tradeoffs amongst carbon and currently regulated pollutants;
- Consider streamlined permitting that allows permits for projects that offer GHG emissions reductions to be expedited;
- Use this information to inform policy makers.

The TWG recommends these overarching considerations be addressed in the next phase of analysis.

Estimated GHG Savings and Costs Per MMT CO_2e

- **Required analysis to be accomplished**

1) Analysis of costs/benefits for different mechanisms of carbon or CO_2 capture, from produced gas, and removed pre and post combustion. Options should be compared on a tons CO_2 avoided basis (tons CO_2 captured – tons CO_2 generated by capture, transport, and storage processes).
2) Identification and cost estimate of additional infrastructure that would be required capture of CO_2.
3) Identification and cost estimate of additional facilities that would be required for transport and injection of CO_2 .
4) Identification and cost estimate of new or upgraded well construction if required for injection of potentially corrosive (if mixed with H_2O) CO_2. Studies are needed to determine how well materials hold up to long term exposure to various concentrations of CO_2EOR analysis of reservoir

- **Data sources for the analysis, methods, and assumptions**

Consultant for evaluation
Prudhoe Bay Operators
Literature search on capture and sequestration (EPA, IOGCC, DOE, IPCC special report, API)

- **Key uncertainties to be captured in the studies**

Cost
Hydrocarbon reserves impact
Technology
Regulatory Environment
    What amount of leakage is authorized (any? a percentage?)
Long term CCS (How long is long term?)
Liability, how long, who?
Public acceptance NIMBY

<u>Feasibility Considerations</u>

- Costs
- Available technology, technology maturity
- Legal issues, will long term injection be approved?
- Liability, who is responsible long term?
- Ownership of pore space
- Long term monitoring
- Conflicting regulatory requirements
- Time Frame, how long to permit? Build?
- Logistics, space for new facilities? Availability of new required equipment?
- Public acceptance of long term storage
- Availability of resources (water, power)

<u>Additional Information</u>

Are there any additional Benefits and Costs that are not directly Greenhouse Gas related that we should highlight. These would include, but are not limited to an overall Fuel Savings (lower waste), Lower NOx, Lower SO_2, And Lower PM?

- **Benefits**
    - EOR benefit

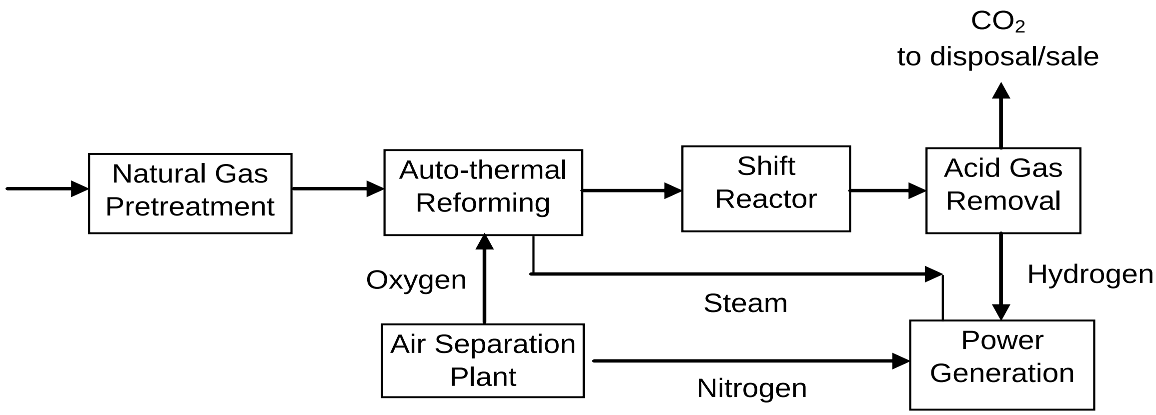
  - Incentive driven potential to replace aging facilities if synergistic with capture and sequestration
  - Employment opportunities

- **Costs**
  - Parasitic energy demand 10-50% extra power requirements, possible additional water requirements. Impacts on state royalties and company income
  - Increase cost of fuel impacts overall cost of living
  - Increased operating costs
  - Impact on Global competitive standing if cost structure in US significantly higher than places without emissions limits.

Appendix B: Process Options for CO_2 Emissions Reduction
Processing options for minimizing CO_2 emissions in oil and gas operations are typically categorized into the following:

- **Pre-combustion Capture** involving decarbonization or production of a hydrogen fuel from reforming of natural gas and capture of CO_2 created in the reforming process.
- **Post Combustion Capture** involving the removal of CO_2 from flue gas produced in combustion of natural gas.
- **Oxy-firing** involving combustion of fuel gas/natural gas in oxygen instead of air, producing an easily separable wet CO_2 flue gas.
- **Fuel Gas Treating** involving the removal of CO_2 from the natural gas used as fuel for fired equipment, thus limiting total CO_2 emissions from the combustion process.

Pre-combustion Capture involves multiple processing steps to convert natural gas to a hydrogen stream and a CO_2 stream. The CO_2 is captured and is available for sale, other uses, or disposal. The hydrogen produced in the process is used for power generation fuel thus eliminating CO_2 emissions associated with the combustion of natural gas. The process involves reforming (auto-thermal reforming with a shift reactor) which has the added benefit of creating a great deal of heat typically used to produce steam for power generation or compressor power. This type of process is typically part of an integrated power generation station that includes maximum thermal efficiencies to create electrical power with minimal Green House Gas emissions. The process requires significant water treating, extensive pre-treatment facilities, and includes an air separation plant to feed the natural gas reforming operation.



Post Combustion Capture involves diverting the hot flue gas from combustion of natural gas, cooling the flue gas and then contacting the flue gas with a solvent to remove the CO_2. Flue gas from the combustion process is at a very low pressure and typically contains less than 10% CO_2. The flue gas is wet (water being a by-product of combustion), so this stream is also very corrosive. The flue gas is too hot after combustion to process, so the flue gas is cooled by extracting the heat in a waste heat recovery process and then cooled by direct contact with water. Typically, a blower is required to provide added pressure to move the flue gas through the processing unit. The cooled flue gas is contacted with an aqueous solvent (amine based) and the CO_2 is chemically removed from the flue gas. The CO_2 is then removed from the solvent by a regeneration process. The CO_2 is at low pressure and will need to be dehydrated and compressed for disposal or sale. The flue gas is then vented to the atmosphere. Due to the very low pressures associated with this process, the equipment required (ducting, contacting vessels) is very large. The process also requires significant heat to regenerate the solvent.

Oxy-firing involves the combustion of fuel gas or natural gas in near-pure oxygen instead of air. This produces a flue gas that contains mostly water and CO_2. The water is easily condensed, leaving a near-pure stream of SO_2 which can be dehydrated, purified and compressed for disposal or sale. A portion of the flue gas is recycled to moderate combustion temperatures. The oxygen is provided by an air separation unit (ASU) which cryogenically distills air into its major components. The substantial power requirement of the ASU remains a challenge for oxy-firing, although it is often viewed as a potentially favorable alternative to post-combustion capture.

Fuel Gas Treating involves removing the CO_2 from the natural gas before combustion. This process is similar to the Post Combustion Capture process, but since the natural gas is typically dry and at an elevated pressure, the processes used for this can be more efficient. Solvent processes (using a chemical solvent or a physical solvent) are the norm in the processing industry for gas treating. Alternative processing utilizing membranes is also an accepted industry practice. The fuel gas is contacted with a solvent or directed through a series of membranes and then is available for use as fuel. The CO_2 is removed from the solvent by regenerating the solvent (using heat or reduced pressure) or in the case of the membranes simply piped from the membranes to CO_2 compression and disposal. The treated natural gas is then ready for fuel use with a minimum of processing or handling.

O&G 8: Carbon Capture and Geologic Sequestration away from Known Geologic Traps

Executive Summary

This option relates to the technical and economic feasibility of CO_2 capture, transport and geologic sequestration far from oil and gas infrastructure, and where a nearby storage reservoir is not proven. The capture and storage aspects, while similar in many aspects to those described in O&G 7 for sources near existing Alaska oil or gas fields, differ in two important aspects, 1) the type of capture mechanisms that are applicable for coal are different than those used for natural gas, and 2) the fact that there are no known reservoirs nearby means that either a long pipeline needs to be built, or an exploration program to prove up an appropriate storage reservoir needs to be executed.
The stationary sources of CO_2 emissions in Interior Alaska are related to power generation from coal or diesel combustion, and the closest proven reservoirs likely to be capable of sequestering CO_2 are in the Cook Inlet basin (250-350 miles away.) (See Appendix A for additional details.)

Potential Benefit to State

The 2002 estimate of CO_2 emissions related to power generation in the Fairbanks area is 2 MMT CO2e, about 1/10th of all the stationary GHG emissions in Alaska. Technically, a significant portion could be captured and injected if the appropriate capture technology could be built, and a suitable storage site found.

Qualitative Summary of the Potential Cost and GHG Savings

Huge (100's of millions???) of capital expenditures will be required by facility owners as significant retrofitting of existing power generating facilities will be needed. In addition, significant amounts of fuel are needed to power the capture and injection process. Dependant on the type of capture technology chosen, additional water resources may also be required. More very large expenditures (10's to 100's of millions) will be needed for either an exploration program (wells, seismic, reservoir simulations) or a long (350 mile?) CO_2 pipeline. Additional funding will be required for injection wells and a long term monitoring program.
Significant commitment from State regulatory departments will be needed to overcome existing hurdles in the permitting and regulatory environment.

Policy Implications/recommendations

Because of the additional use of fuel required for capture, transport, and injection of CO_2, and the resultant GHG emissions related to its combustion, this option should be implemented only after or possibly concurrently with any and all energy efficiencies that can be put into place to first reduce emissions. The less fuel burned overall, the less GHG to deal with.
Key hurdles are investment/ capital cost and regulatory environment. Policies should focus on:

a) Encouraging investment through incentives (see details in full Appendix A.)

b) Simplifying/streamlining the regulatory environment:

c) Avoid overlapping regulations, ie State and Federal both regulating GHG emissions and underground injections. Recommend coordinating/participating with development of Federal regulations to both insure the regulations fit Alaska, to allow early implementation.

d) Study State permitting/regulatory personnel requirements. Establish policies to pay and retain sufficient qualified employees to do the job.

Implementation Path

To minimize time required for implementation, regulatory and capital investment hurdles should be addressed immediately. Critical path is for State to design incentives appropriate for capital investments, operators to begin design of facilities and permitting needed to strip the CO_2 from the individual fuel exhaust streams, and start either an exploration program to find a reservoir suitable for sequestration nearby, or the planning for a long pipeline. Capture technology studies should include space, power requirements, and water requirements for each facility. Finally, the State and operators should immediately start working the complicated regulatory/permitting issues. Final economics will depend on the value for carbon. Financing CCS projects will be sensitive to that value, and will be dependent on future cap and trade or carbon tax legislation.

Research Needs

Economic research:

g) Model and recommend most effective incentives. Model effects on economy and jobs with various scenarios.

h) Research long term value of carbon – huge impact on economics of these projects.

Technical research:

Study the technical feasibility of capturing CO_2 from coal and diesel power generation facilities in and around Fairbanks. Study economics of long pipeline as compared to the cost of an exploration program.

Note: This option deals with emissions outside the oil and gas sector. The O&G TWG was responsible for all CCS options as the geologic expertise was located in this TWG.

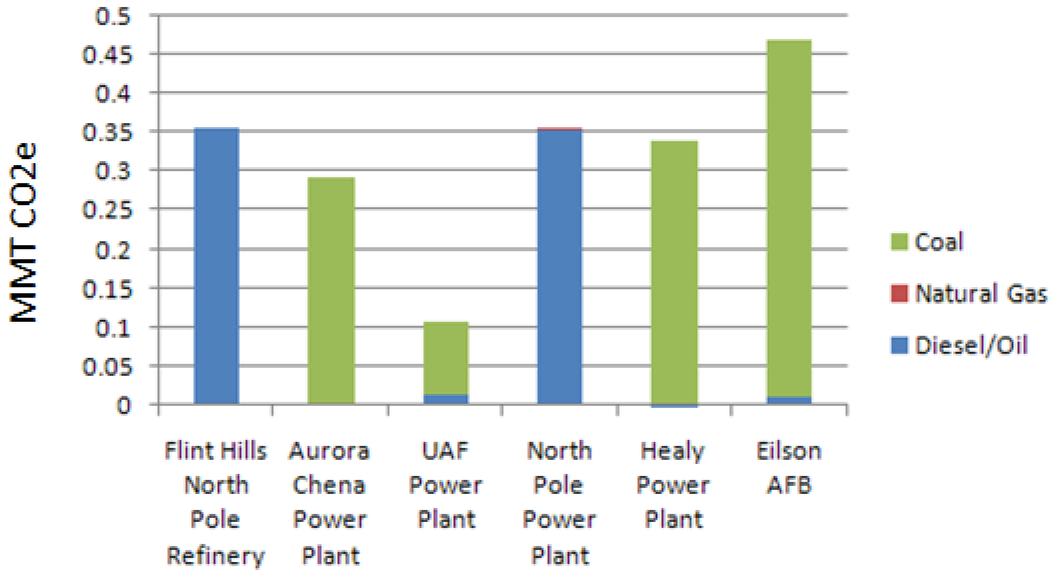
O&G 8 Appendix A: Additional Supporting Documentation

Carbon Capture and Geologic Sequestration away from Known Geologic Traps.

Option Details

Purpose: As described in O&G 7, CO_2 capture, transport, and geologic sequestration (CCS) involves multiple, new and complex technology. It is critical to thoroughly understand the current technologies that could be applied for all aspects of a CCS project (capture, transport, and sequestration of CO_2) especially from sources far from proven geologic traps. An understanding of the risks and expected costs related to the different technologies, as well as the risks inherent in choosing a long term sequestration site, are critical in choosing the best projects for Alaska.

Outside of the North Slope and Cook Inlet, the largest CO_2sources are in interior Alaska, in and around the Fairbanks area. These sources encompass about 10% of Alaska's stationary sources of CO_2 (~2MMT CO_2e) with approximately 60% due to the burning of coal, and the rest related to the combustion of diesel fuel.



The extreme temperatures, geologic uncertainty, and environmental sensitivity in interior Alaska provide a unique operating environment that needs to be well understood before large scale capture and sequestration can responsibly begin.

Specific Recommendations:
Risks and uncertainties in the following categories should be addressed:

- Maturity of capture technology for coal and diesel combustion sources
- Costs for capture, transport, and sequestration
- Costs for geological and geophysical studies for site selection
- Potential for CO_2 leakage

Detailed analysis should cover:

- Pros and cons of various capture technologies for coal or diesel power sites
- Identification of potential basins with geologic sequestration potential
- Identification and costs of geological and geophysical analysis required to provide confidence that chosen formation will provide long term geologic sequestration of injected CO_2 (ie test wells, down hole well testing, maintenance and repairs, reservoir analysis and simulation studies)
- Facilities requirements (including additional space needs)
- Additional power and water resource requirements
- Costs for new facilities, 'parasitic' power, and water requirements
- Logistics and Costs for CO_2 pipelines assuming nearby sink can be found
- Logistics and Costs for CO_2 pipelines assuming long transport required
- Value from possible tax or carbon credits
- Potential value for Enhanced Oil Recovery (EOR) if no local sequestration sites can be found (Cook Inlet, or if exploration efforts are successful, Nenana or Yukon Flats basins are potential EOR site)
- Estimates of CO_2 emissions that could be avoided (including additional emissions from capture,transport,and injection operations)

- Logistical issues related to construction and operations in an extreme temperature environment
- Risk assessment for long term storage
- Regulatory requirements (ie EPA UIC program, other state and federal requirements)
- Long term monitoring needs (pre , during, and post injection)

Timing:
Studies could start immediately dependent on resources and funding. Early studies will facilitate the earliest possible implementation. Implementation of CCS in interior Alaska will require significantly more time and money than in and around established oil and gas fields, as either a) an exploration program to establish the presence of a suitable geologic sequestration site in interior Alaska (most likely the Nenana basin) needs to be performed, or b) a long (perhaps 250-350 mile) pipeline to a suitable storage site, the closest proven in the Cook Inlet basin, would need to be built.

CCS Background:

This option encompasses multiple aspects of carbon capture, transport, and geologic sequestration.
Capture: Technology exists (in various stages of maturity) for pre-combustion carbon removal, post-combustion CO_2 removal from exhaust gases, oxy-firing, and CO_2 removal prior to the burning of fuel gas (not currently an issue for interior Alaska-See Appendix B for a more detailed description of these processes.) CO_2 removal from produced and exhaust gases have been commercially applied, while oxy-firing and pre combustion removal processes are in earlier stages of development. Most combustion related projects are still tied to government subsidies, and while research is ongoing to improve efficiencies, current technologies can require significant resource commitments in energy and water. 'Parasitic' energy (the additional energy required for the capture and injection of CO_2 for the same power output) requirements are in the 10-50% range, dependent on the source of the CO_2 and the mechanism used for removal. 'For example, capture of 90 percent of the CO_2 from a supercritical pulverized coal (SCPC) plant using current technologies would result in increased fuel consumption of 24-40 percent compared to similar plants without CO_2 capture and compression (IPCC 2005).' (World Resources Institute (WRI) Guidelines for Carbon Dioxide Capture, Transport, and Storage, pg 25, www.wri.org). The appropriate technology for capture and removal of CO_2 will need to be evaluated and adapted on a site specific basis. Construction of additional facilities will be required, and space for facilities will be an important consideration. It is far more efficient to plan the additional space and resource requirements in the original design than to try to fit them in after facilities are already operating.
Transport: Once the CO_2 is captured, it must be transported to the eventual sequestration site. The CO2 must be dehydrated and compressed for transportation and injection. For interior Alaska, pipelines (in the worst case as long as 250-350 miles to the nearest confirmed geologic sequestration potential) will need to be constructed to safely transport the compressed CO_2 to the ultimate sequestration site. Existing CO_2 pipelines operate at pressures ranging from 1,250-2,200 psi., higher than is required for a natural gas pipeline. (WRI, p.45.) CO_2 pipelines are expensive to build, but are common in the lower 48 United States, with an estimated 0.78 trillion cubic feet of CO_2 per year transported through an estimated 3,900 miles of pipelines, mainly for use in EOR (Enhanced Oil Recovery). (WRI, p42)
Geologic Sequestration: Next, the CO_2 must be injected, using corrosion resistant wells, into a geologic container that will not result in leakage of the CO_2 to the surface. The geologic container should be sufficiently deep to keep the CO_2 in its dense, supercritical liquid, phase (typically deeper than about 2500 ft.) Leakage can be due to insufficient seal capacity as well as breaches to seal integrity. The

nearest proven seal and trap are in the Cook Inlet Oil and Gas fields, approximately 350 miles away from Fairbanks. While they could exist, seal capacity (the ability to trap CO_2) and a trapping mechanism have yet to be proven in interior Alaska. Even where sufficient seal capacity and a trap exist, seal breaches can still occur due to excessive injection pressures, well bore integrity breakdown, or faulting due to seismic events. Seal integrity could also be compromised by excessive injection pressures or seismic events that could potentially open up faults that were previously non-conductive. Finally, as injected CO_2 contacts reservoir water, the reservoir acidifies, ,and the environment becomes more corrosive. Both surface and sub-surface facilities will need to be carefully managed for corrosion..

Reservoir selection will be a challenge in interior Alaska as currently there are no identified sequestration sites. Geologically, Fairbanks is underlain by metamorphic rocks that are highly sheared and faulted and would have very limited, if any, CO_2 trapping capacity. The nearest coal-bearing sedimentary rock is in the Nenana basin to the south west which is likewise highly deformed. Still unknown is the potential in the Nenana basin for saline reservoir storage, though an Exploration License is currently active in that area. An oil and gas exploration well (currently being planned) could add much needed information to answer whether there is prospective CO_2 geologic sequestration potential in a saline reservoir. To confirm sequestration potential, additional wells, seismic data acquisition, and computer modeling would likely be required before proof of ability to sequester long term would be established. With current information, however, the ability of a rock to sequester CO_2 for any length of time is completely unknown.

Possible long term sequestration potential exists in unmineable coal seams known to exist in interior Alaska, but this technology has significant hurdles and long term injection into coal seams has not yet proven feasible, especially in areas where permafrost can be expected.

Finally, risk assessment and a long term monitoring program will be required for all sequestration projects. EPA is currently working on regulations that will be applied to sequestration projects, but long term (time frame still to be defined) post-injection monitoring will certainly be an expectation for any sequestration site.

Geographic Focus:

Fairbanks area in Interior Alaska

Approximately 2 MMT CO_2e is generated within approximately 100 miles of Fairbanks, but no proven geologic sinks are in that area. There is potential for future coal gasification plant in Fairbanks which would generate additional GHG emissions.

Evaluation Focus Areas

- **Who needs to be involved with study**

– Consultants for study on technical and economic feasibility

– Companies related to emissions sources.

– Companies related to potential geologic sinks

– Operators of oil fields who might benefit from CO_2EOR

– State of Alaska (ADNR, AOGCC, ADEC, ADOR, etc) and other regulatory agencies (EPA, FERC, RCA, etc)

– Local land owners (ie Doyon Native Corporation) as applicable

- **Relevant legislation and regulations**

Existing

- EPA regulations for underground injection for EOR

Under development or needed

- EPA regulations regarding CO_2 Underground Sequestration.[21] The State may seek primacy for this activity upon final EPA rulemaking.
- EPA regulations, if any, and other federal laws regarding air quality, carbon tax or cap and trade, etc
- State/local government Permitting as necessary addressing issues beyond EPA UIC CO_2 sequestration rules
    - Ownership issues, surface rights vs mineral rights vs pore space rights
    - Long term liability at sequestration sites
    - Royalties and lease term impacts of CO_2 sequestration and use for EOR
    - Land use regulations and requirements
- Potential Federal cap and trade legislation and ultimate EPA air quality regulations
    - Potential conflict between increased fuel use (decreased hydrocarbon reserves) due to capture and injection, and benefits for reduction of CO_2 through sequestration

- **Incentives : Financial, Permitting, etc**

- Tax incentives exist in current federal Energy Plan (part of Bailout Bill.)
- Additional carbon credits, amount to be determined based on analysis
- Streamline permitting critical for project turnaround

<u>Related Programs and Policies</u>

This option is strongly related to and dependent on other options being proposed by the Oil and Gas Technical working group.
Carbon Capture and Geologic Sequestration near existing oil and gas fields: O&G 7

This option will present major challenges in implementation in logistics, time, and cost. It should be planned and implemented in conjunction with as much energy efficiency and reductions of produced emissions as possible.

[21] New EPA Underground Protection Control Proposed rules for new Class VI Underground Protection Control have been out for comment (comments due 12/24/08). AOGCC participating through Interstate Oil and Gas Compact Commission and Ground Water Protection Council. State may apply for primacy when final rules are adopted. See www.epa.gov/ogwdw/uic/wells_sequestration.html for further information.

<u>Overarching Considerations</u>

On a broader scale, the following overarching considerations are recognized as critical to maximizing implementation efficiency of any Carbon Capture and Geologic Sequestration Project. The State of Alaska should:

- **Evaluate how possible GHG regulation programs (cap-and-trade, carbon tax, command and control) could impact any given project given today's economics and technology;**
- **Avoid complicating the regulatory environment with potentially conflicting regulations with existing or expected federal regulations**
- Assure Up-Front Planning for budget, staffing, etc.;
- Prepare for regional tradeoffs amongst carbon and currently regulated pollutants;
- Consider streamlined permitting that allows permits for projects that offer GHG emissions reductions to be expedited;
- Use this information to inform policy makers.

The TWG recommends these overarching considerations be addressed in the next phase of analysis.

<u>Estimated GHG Savings and Costs Per MMT CO_2e</u>

- **Required analysis to be accomplished**

1) Analysis of costs/benefits for different mechanisms of carbon or CO_2 capture, from produced gas, and removed pre and post combustion. Options should be compared on a tons CO_2 avoided basis (tons CO_2 captured – tons CO_2 generated by capture, transport, and storage processes).
2) Identification and cost estimate of additional infrastructure that would be required for transport and injection of CO_2 to injection sites.
3) Identification and cost estimate of new or upgraded well construction if required for injection of potentially corrosive (if mixed with H_2O) CO_2. Studies are needed to determine how well materials hold up to long term exposure to various concentrations of CO_2
4) EOR analysis of reservoir
5) Investigation of use of underground coal gasification in place of surface coal gasification to reduce overall emissions

- **Data sources for the analysis, methods, and assumptions**

Consultant for evaluation
Cook Inlet Operators (in the case the pipeline has to extend that far)
Doyon and partners (if exploration in the Nenana or Yukon Flats basins in successful)

Literature search on capture and sequestration (EPA, IOGCC, DOE, IPCC, API)

- **Key uncertainties to be captured in the studies**

Cost
Technology
Regulatory Environment
    What amount of leakage is authorized (any? a percentage?)
Long term CCS (How long is long term?)
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Feasibility Considerations

- Costs
- Available technology, technology maturity
- Legal issues, will long term injection be approved?
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Additional Information

Are there any additional Benefits and Costs that are not directly Greenhouse Gas related that we should highlight. These would include, but are not limited to an overall Fuel Savings (lower waste), Lower NOx, Lower SO_2, And Lower PM?

- **Benefits**
  - Potential EOR benefit
  - Incentive driven potential to replace aging facilities if synergistic with capture and sequestration
  - Employment opportunities
- **Costs**

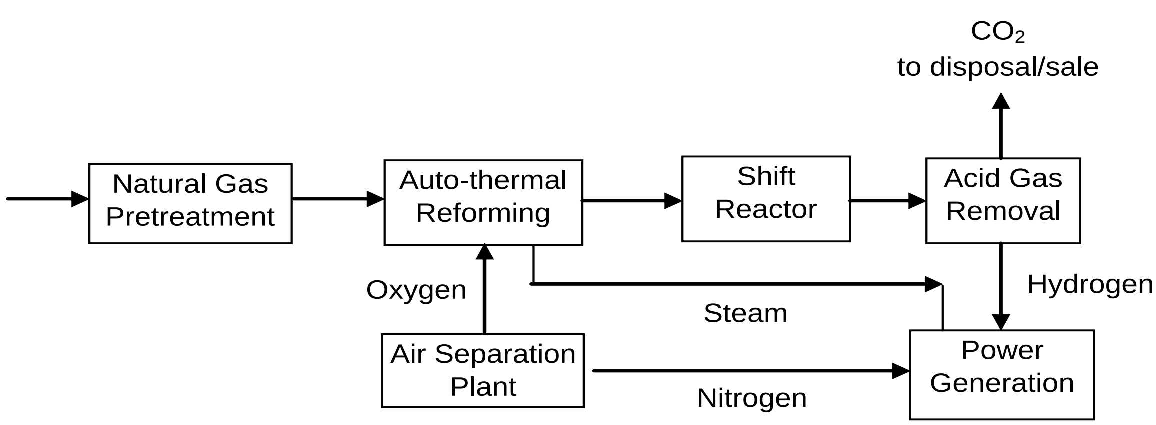
- Parasitic energy demand 20-50% extra power requirements, possible additional water requirements. Impacts on state royalties and company income
- Increase cost of fuel impacts overall cost of living
- Increased operating costs

Appendix B**:** Process Options for CO_2 Emissions Reduction

Processing options for minimizing CO_2 emissions in oil and gas operations are typically categorized into the following:

- **Pre-combustion Capture** involving decarbonization or production of a hydrogen fuel from reforming of natural gas and capture of CO_2 created in the reforming process.
- **Post Combustion Capture** involving the removal of CO_2 from flue gas produced in combustion of natural gas.
- **Oxy-firing** involving combustion of fuel gas/natural gas in oxygen instead of air, producing an easily separable wet CO_2 flue gas.
- **Fuel Gas Treating** involving the removal of CO_2 from the natural gas used as fuel for fired equipment, thus limiting total CO_2 emissions from the combustion process.

Pre-combustion Capture involves multiple processing steps to convert natural gas to a hydrogen stream and a CO_2 stream. The CO_2 is captured and is available for sale, other uses, or disposal. The hydrogen produced in the process is used for power generation fuel thus eliminating CO_2 emissions associated with the combustion of natural gas. The process involves reforming (auto-thermal reforming with a shift reactor) which has the added benefit of creating a great deal of heat typically used to produce steam for power generation or compressor power. This type of process is typically part of an integrated power generation station that includes maximum thermal efficiencies to create electrical power with minimal Green House Gas emissions. The process requires significant water treating, extensive pre-treatment facilities, and includes an air separation plant to feed the natural gas reforming operation.



Post Combustion Capture involves diverting the hot flue gas from combustion of natural gas, cooling the flue gas and then contacting the flue gas with a solvent to remove the CO_2. Flue gas from the combustion process is at a very low pressure and typically contains less than 10% CO_2. The flue gas is wet (water being a by-product of combustion), so this stream is also very corrosive. The flue gas is too hot after combustion to process, so the flue gas is cooled by extracting the heat in a waste heat recovery process and then cooled by direct contact with water. Typically, a blower is required to provide added pressure to move the flue gas through the processing unit. The cooled flue gas is contacted with an aqueous solvent (amine based) and the CO_2 is chemically removed from the flue gas. The CO_2 is then removed from the solvent by a regeneration process. The CO_2 is at low pressure and will need to be dehydrated and compressed for disposal or sale. The flue gas is then vented to the atmosphere. Due to the very low pressures associated with this process, the equipment required (ducting, contacting vessels) is very large. The process also requires significant heat to regenerate the solvent.

Oxy-firing involves the combustion of fuel gas or natural gas in near-pure oxygen instead of air. This produces a flue gas that contains mostly water and CO_2. The water is easily condensed, leaving a near-pure stream of SO_2 which can be dehydrated, purified and compressed for disposal or sale. A portion of the flue gas is recycled to moderate combustion temperatures. The oxygen is provided by an air separation unit (ASU) which cryogenically distills air into its major components. The substantial power requirement of the ASU remains a challenge for oxy-firing, although it is often viewed as a potentially favorable alternative to post-combustion capture.

Fuel Gas Treating involves removing the CO_2 from the natural gas before combustion. This process is similar to the Post Combustion Capture process, but since the natural gas is typically dry and at an elevated pressure, the processes used for this can be more efficient. Solvent processes (using a chemical solvent or a physical solvent) are the norm in the processing industry for gas treating. Alternative processing utilizing membranes is also an accepted industry practice. The fuel gas is contacted with a solvent or directed through a series of membranes and then is available for use as fuel. The CO_2 is removed from the solvent by regenerating the solvent (using heat or reduced pressure) or in the case of the membranes simply piped from the membranes to CO_2 compression and disposal. The treated natural gas is then ready for fuel use with a minimum of processing or handling.

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